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ELECTRIC POWER ANNUAL REPORT

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HISTORY
1985–89

* * * *

PROJECTIONS
1990–99

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A REPORT OF THE
EDISON ELECTRIC
INSTITUTE

-A4700-211

Capacity and Generation of Non-Utility Sources of Energy.
Presents statistics compiled from electric utility reports and other sources for 1988 and a limited amount of historical data on capacity and electric generation of non-utility producers of energy (cogenerators, small power producers and other non-utility producers). The report contains national data on capacity and generation by year, type of producer and qualifying status; number and size of projects; electric utility receipts from non-utility producers from 1979 through 1988; yearly additions of capacity from 1980 through 1988; type of connection and dispatchability; prime mover; primary energy source; and major industry group. Published annually in the spring. 80p.

Catalogue of Investor-Owned Electric Utility Companies Operating in the United States.
Complete reference of investor-owned electric utility names, addresses and phone numbers, arranged on a state basis according to location of principal office. Holding companies and systems, and jointly-owned companies are cross-referenced with operating subsidiaries. Ranking of companies according to number of ultimate customers is presented. Published annually in the fall. 48p.

Digest of Electric Utility Financial Ratios.
Provides a method of calculation for the predominant ratios used by the industry in analyzing financial reports. Categories of ratios include Earnings and Return; Common Dividend; Coverages, Interest and Preferred Dividend; Balance Sheet; Revenues and Sales; Expense; Tax; Plant; Depreciation; other ratios, such as funds used during construction as percent of earnings and per share, capital expenditures, etc. Prepared by EEI Financial Ratios Subcommittee of the Statistical Committee. 31p.

EEI Pocketbook of Electric Utility Industry Statistics.
A pocket-sized quick reference of national electric utility industry data, some dating from the early 1900's. Categories include data on installed capacity, generation, capital and finance, sales, revenues, customers, fuels and private and public ownership. Published annually in late fall. 36p.

Electric Power Annual Report.
This report presents historical and projected data concerning the electric power supply, expansion of electric generating facilities, and the manufacture of heavy electric power equipment in the U.S. as of the end of the year. Power supply data including peak loads, capability to meet loads, kilowatthour requirements, load factors, and comparison between summer and winter seasons are shown on a total industry basis for each of the nine reliability councils and for total contiguous U.S. Also included are orders and shipment information on the manufacture of heavy electric power equipment in the U.S. and foreign-made equipment to be imported by U.S. electric power systems. Published annually in the fall. 40p.

Floppy Disk Version of EEI Statistical Yearbook.
Contains eighty-nine (89) LOTUS 1-2-3 files on three disks that print out as close approximations of the tables in the Statistical Yearbook. Filenames are in the form TABLEnn.WK1. Wherever possible, the same number of years have been included as in the printed version of the Statistical Yearbook. The LOTUS worksheet format facilitates easy extraction and manipulation of data series from the Yearbook tables without re-keying, as well as allowing the options of producing whole tables (or selected parts) in hard copy and LOTUS graphics. In addition to a "README" file on the first disk, each floppy contains a FILEINFO.WK1 worksheet file with descriptions of each table's contents, the same data in FILEINFO.PRN form that can be "typed" to the PC screen, and a FILEINFO.COM program with paging, printing, and keyword-finding functions to manipulate the table titles. Available in the winter.

Glossary of Electric Utility Terms.
Defines the principal statistical reporting terms commonly used in the electric utility industry. Since the last revision in 1970, the Glossary has been expanded to include information and terms on Load Management/Rate Design, Nuclear Generation and additional terms on financial and general operations. Prepared by the EEI Glossary of Electric Terms Subcommittee of the Statistical Committee. 56p.

Guidelines for Defining & Classifying Electric Customers by Major Energy Use.
Provides guidelines within the electric utility industry for counting, classifying, and summarizing customers, categorizing sales and revenues by major energy use, and determining average use and average revenue per customer. The report contains definitions as well as the application of the definitions to specific situations and problem areas. Historically, the industry has based its classifications on rate schedules and it is probable that the recommendations in this report are unsuitable for rate analysis. However, the recommendations are offered as a basis for making a more significant market-oriented representation of sales statistics available to the industry, security analysts, and others with interest in electric utilities. 8p.

Post-Summer Electric Power Survey.
Reports results of a scheduled generating additions survey as of July 1, and a summer peak load survey as of September 15. There are listings of actual additions to generating capacity during the first half of the year and of those scheduled for the future. Contains first actual regional capability, peak load, and percent capacity margin values for the summer season just completed.

NERC's latest ten-year fuel projections are presented in terms of both regional generation from each energy source, and . physical units of coal, oil and gas to be burned for electric generation. Also includes information on the manufacture of heavy electric power equipment in the U.S. and foreign-made equipment to be imported by U.S. electric utility systems, orders and shipments during the first half and shipment backlogs as of July 1. Published early the next year. 40p.

Problems and Limitations of Intercompany Comparisons of Investor-Owned Electric Utilities.
Assists analysts and others who may wish to make industry-wide comparisons of investor-owned electric utilities. The report illustrates some of the main factors that can facilitate valid intercompany differences in performances. The Executive Summary briefly examines some of the more important factors that lead to performance differences between companies. The Discussion Section covers in greater detail many of the factors that can generate invalid and inaccurate comparisons. Prepared by EEI Problems and Limitations Subcommittee of the Statistical Committee. 51p.

Statistical Releases.
Yearly subscription includes: 1) *Electric Output,* issued weekly for nine geographic divisions and total U.S.; data for latest 52-week period and calendar year to date; latest quarterly data for installed capacity, generation, customers and sales, 2) *Quarterly Statistical Report,* presents latest sources of electricity, including net generation, net imports of electricity, and net amounts available for distribution; customers, sales, and revenues by class of electric service; average use and revenue data, 3) *Advance Release,* issued in summer, includes selected tables that appear later in Statistical Yearbook, 4) *Statistical Yearbook of the Electric Utility Industry.*

Statistical Yearbook of the Electric Utility Industry.
Data compiled from company reports and other sources on operational and financial aspects of the total electric utility industry. Categories include national and state statistics on installed capacity; electric generation and supply; sales, revenue and customers by class of service; investor-owned data for operating and related ratios; fuel use; financial; and general economics series. Prepared under the general guidance of the EEI Statistical Committee. Published annually in the fall. 101p.

Statistics, Non-Investor-Owned Electric Utilities.
Financial and operating data on government-owned (municipal, state/public power district and federal) and government-financed (cooperative) electric power systems. Tables present data on installed capacity, generation, customers, sales and revenues, in addition to selected financial data. This publication supersedes *Government Power* which was last published in 1985 and presented statistics for 1983. 40p.

Statistics on Fuel Used to Generate Electricity by the Electric Utility Industry.
Fuel data are presented for the U.S. by state and Census Division, detailed by type of fuel (coal, oil, natural gas and nuclear) for both the Total Electric Utility Industry and the Investor-Owned segment. Heat rate, average Btu content, and cost of fuel per kilowatthour, per million Btu, and per unit consumed are shown for the most recent and four preceding years. Published annually in the fall. 75p.

A REPORT OF THE STATISTICS DEPARTMENT OF THE EDISON ELECTRIC INSTITUTE

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MANUFACTURERS OF HEAVY ELECTRIC POWER EQUIPMENT

--Domestic--

Babcock & Wilcox Co.
Brown-Boveri Turbomachinery, Inc.
B & W Nuclear Technologies
Combustion Engineering, Inc.
Cooper-Bessemer Reciprocating
Elliott Company
Fairbanks Morse Engine Div., Colt Industries
Foster Wheeler Energy Corp.
General Electric Co.
Imo Industries, Inc.
Kuhlman Corporation
McGraw-Edison Power Systems
North American Transformer
Riley Consolidated, Inc.
RTE Corporation
Voith Hydro, Inc.
Westinghouse ABB Power T&D Co.
Westinghouse Electric Corp.

--Foreign--

American Elin Corporation
ASEA Brown Boveri, Inc.
Canadian General Electric Co., Ltd.
English Electric Corporation
Fuji Electric Power Co., Ltd.
Hitachi, Ltd.
John Brown Engineering, Ltd.
Mitshubishi Heavy Industries, Ltd.
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U.S. REGIONS OF THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

IDENTIFICATION OF RELIABILITY COUNCILS:

ECAR—East Central Area Reliability Coordination Agreement
ERCOT—Electric Reliability Council of Texas
MAAC—Mid-Atlantic Area Council
MAIN—Mid-America Interconnected Network
MAPP—Mid-continent Area Power Pool
NPCC—Northeast Power Coordinating Council
SERC—Southeastern Electric Reliability Council
SPP—Southwest Power Pool
WSCC—Western Systems Coordinating Council

The electric utility systems of the United States are normally operated as three separate interconnected areas: the Eastern Interconnection, the Electric Reliability Council of Texas (ERCOT), and the Western Systems Coordinating Council (WSCC). Generating capacity available in one of these areas is not usually available to any other area. Also, generating capacity in one of the interconnected areas may not be available to serve load throughout that area due to various internal constraints.

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FOREWORD

This 1989 ELECTRIC POWER ANNUAL REPORT presents information concerning the electric power supply, expansion of electric generating facilities, and the manufacture of heavy electric power equipment in the United States as of the end of 1989.

The report is divided into three parts. Part I covers the history of electric power supply from 1985 through 1989. Part II pertains to projected power supply values from 1990 through 1999. Part III has to do with the planned domestic manufacture and importation of heavy electric power equipment as of January 1, 1990.

The historical data from 1985 through 1989 are an accurate presentation of the peak load, capability installed to meet load, and energy requirements for these time periods. The electric power supply data shown in Parts I and II of this report are derived from IE-411 reports for previous years submitted to the Department of Energy and to the North American Electric Reliability Council (NERC).

Forecast values used herein were obtained from IE-411 reports and from the advance release of ELECTRIC POWER SUPPLY & DEMAND 1990-1999 published by NERC in June of 1990. Installed capability, peak load and percent capacity margin values shown in this report for the summer of 1989 update the preliminary actual values published in EEI's 1989 POST-SUMMER ELECTRIC POWER SURVEY. The installed generating capability figures for summer 1989 and winter 1989/90 were reported to NERC in connection with its annual reliability review assessment.

Data in this report represent the total electric utility industry of the lower 48 states, including Investor-Owned systems and those of governmental agencies--Federal, Municipal and State & Local--and also Rural Electric Cooperatives.

The reported data include some industrial power installations whose operations are coordinated with the utility systems with which they are interconnected and which thereby contribute to the public supply. The data do not include any isolated industrial or institutional power installations.

Data pertaining to power system capabilities, peak loads, percent capacity margins, and energy requirements are presented for each of the nine reliability councils of NERC. Boundaries of the nine reliability councils are shown by the map in Fig. 1. The North American Electric Reliability Council encompasses essentially all utility systems in the United States and five Canadian provinces, but the data presented in this report cover only the systems in the contiguous United States.

Part III of this report presents the results of the semi-annual survey on the manufacture and scheduling of heavy electric power equipment as of January 1, 1990, conducted by the Statistics Department of the Edison Electric Institute. Contributors to the survey include representatives of the electric utility industry throughout the contigous United States, the nation's principal manufacturers of heavy electric power equipment, and those foreign manufacturers supplying electric generating equipment to U.S. electric utility systems.

The Edison Electric Institute is the only organization servicing the electric utility and allied industries that conducts surveys on the manufacture and scheduling of heavy electric power equipment on a semi-annual basis. These surveys are also unique in that information on each planned project is cross-checked with both the manufacturer and the system ordering the equipment. Furthermore, the time-frame for ordered and scheduled units is not limited to ten years, but extends into the future as far out as equipment is officially ordered and scheduled for installation. The resulting data file also allows the semi-annual tracking of unit slippages and cancellations.

Projections presented in this report are based on the best information available from the turn of the year through the end of the first quarter of 1990. There could, however, be delays in the installation of scheduled capacity and reductions in the percent capacity margins. To assure an adequate bulk electric power supply in the 1990s, it is essential that the installation of both nuclear and coal-fired generating units proceed as currently scheduled and that conservation and load management programs be pursued at the same time.

Definitions of the terms used in this report, together with information concerning methods of summarizing the data, appear on the following page.

DEFINITIONS AND METHODS OF SUMMARIZATION

INSTALLED CAPABILITY is the maximum load which a generating unit or a group of units can carry under specified conditions for a given period of time. Installed capability values are shown in the historical summer and winter tables.

CAPABILITY, as projected in this report, is equivalent to Planned Resources, defined by the North American Electric Reliability Council to include the total installed generating capacity which is existing, presently under construction, or in various states of planning; plus scheduled capacity purchases, less scheduled capacity sales; less total generating capacity out of service in deactivated shutdown status. This capability must provide for the projected load plus scheduled maintenance, forced outages, system operating requirements, and any unforeseen load. The capabilities of all systems normally interconnected are based upon fully coordinated operation. Peak capability refers to the maximum capability, as defined above, at the approximate time and for the duration of the load referred to, that is, at the time of the summer peak load or the winter peak load. Regional capability, as reported herein, is the sum of the capabilities of the systems serving the region.

PEAK LOAD for a region may be either coincident or non-coincident. It is the sum of the actual or projected peak load of the electric utilities and any self-generating industrial facilities.

HISTORICAL AND PROJECTED INSTALLED MARGIN shown on the summer and winter tables represents the difference between installed capability and peak load. It is the margin available to replace generating equipment out of service due to planned scheduled maintenance, foreced outages, and equipment deratings due to various causes. In addition, installed margin must provide an operating reserve to cover variations in peak load and to regulate frequency and control transmission tie-line schedules.

PERCENT CAPACITY MARGIN is the installed margin divided by capability multiplied by 100.

CAVEATS Because some maximum regional loads may occur in winter rather than in summer, the installed margin for the country as a whole is not necessarily valid with respect to the electric power situation at a particular time. It is also true that regional installed capacity margins (and hence the installed margin for the sum of the regions) in summer or winter have not always represented the minimum or the maximum margin. The extremes of installed capacity margins may be influenced, for example, by the date of bringing new large generating facilities into commercial operation in relation to the time of the annual peak loads--the addition of a very large generating unit just before the peak could give a larger margin during the peak period than that which existed before the time of peak. Also, in areas having high proportions of hydroelectric generating capacity, the lowest margins may occur at times other than when the load is at a maximum because of low capability resulting from minimum water for power generation.

The adequacy of projected power supply cannot be judged solely by the use of installed capacity margins without proper recognition of the potential impact of planned and forced outages of generating equipment. There have been several occasions within the past 15 years when the entire installed margin has been utilized to offset such outages of generating equipment, resulting in system-wide voltage reductions, interruption of interruptible loads, public appeals, and some interruption of firm customer load.

LOAD FACTOR is the ratio of the megawatthour output supplied during a designated period to the output that would have occurred had the peak experienced during that period been constant throughout the period. For example, annual percent load factor is calculated by multiplying annual megawatthour requirements by 100 and dividing by the product of the annual peak load and the number of hours in a year (8,760 in normal years, 8,784 in leap years).

NERC U.S., as used in this publication, is equivalent to the lower forty-eight contiguous states; Alaska and Hawaii are omitted.

AVERAGE ANNUAL COMPOUND GROWTH RATES are calculated on a point-to-point basis, either by taking the fourth root of the difference between the values for the first and fifth historical years in Tables 1, 2, and 4, or the ninth root of the difference between the first and tenth projected years in Tables 10, 11, and 13.

INSTALLATION OF NEW CAPACITY; CAPABILITIES, PEAK LOADS, MARGINS, AND ENERGY REQUIREMENTS

INDUSTRY PERFORMANCE IN 1989

During the year 1989 the electric utility systems of the contiguous United States put into operation 7,312 megawatts of new electric generating capacity. Table 7, which includes all units of 4 megawatts capacity and larger, shows that 25 units with capability ratings aggregating 7,306 megawatts were thermal, and one unit rated at 6 megawatts was hydraulic. Three of the thermal units were powered by nuclear fuel, and four were conventional steam turbine-generators. The individual generating units that make up the 7.3 thousand megawatts added during 1989 are identified in the actual additions listing on page 13.

This newly added capacity contributed to the increase in the total capability, or load-carrying ability, of the U.S. electric utility systems to 685.2 thousand megawatts at the year end--an increase of 1.2 percent over the total at the end of 1988.

Of the total capability of 685.2 thousand megawatts, approximately 88 percent is thermal and the rest is hydraulic. During the past five years the total capability of the country's electric utility systems has increased at an average annual rate of 1.9 percent.

The combined 1989 summer peak load, shown in Table 1 of this report, was 523.4 thousand megawatts or 5.5 percent higher than the 1989/90 winter peak load. This is the twenty-sixth consecutive year during which the combined summer peak load exceeded the peak of the following winter. The point-to-point compound average annual increase between the 1985 and 1989 summer peak loads was 4.1 percent.

As can be seen from Table 2, the combined winter 1989/90 peak load of the contiguous United States was 496.4 thousand megawatts--6.4 percent above the winter 1988/89 peak load. The change in peak load during the past five years, from winter 1985/86, was a net increase of 72.7 thousand megawatts, and is equivalent to an average annual increase of 4.0 percent on a point-to-point compounded basis.

Table 4 shows that during 1989 the energy requirements for the contiguous United States amounted to 2.8 billion megawatthours--2.9 percent higher than the output for 1988. The point-to-point compound average annual increase between 1985 and 1989 for energy requirements was 3.3 percent.

The 1989 annual load factor for the sum of the nine regions was 62.2 percent.

Table 1 – SUMMER INSTALLED CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS (MW)

Regions		1985	1986	1987	1988	1989	89/88 % Chg	Growth Rate 1985–1989*
NPCC	Installed Capability	51,319	51,879	52,531	53,913	54,622	1.3	1.2%
	Peak Load	40,010	39,026	42,651	45,245	45,031	-0.5	4.4%
	Installed Margin	11,309	12,853	9,880	8,668	9,591		
	Capacity Margin	22.0%	24.8%	18.8%	16.1%	17.6%		
MAAC	Installed Capability	47,157	47,626	48,553	48,669	49,829	2.4	1.3%
	Peak Load	37,053	37,527	40,526	43,110	41,614	-3.5	5.0%
	Installed Margin	10,104	10,099	8,027	5,559	8,215		
	Capacity Margin	21.4%	21.2%	16.5%	11.4%	16.5%		
ECAR	Installed Capability	92,960	95,201	95,319	97,121	97,218	0.1	1.9%
	Peak Load	66,293	69,253	72,561	79,149	75,442	-4.7	4.7%
	Installed Margin	26,667	25,948	22,758	17,972	21,776		
	Capacity Margin	28.7%	27.3%	23.9%	18.5%	22.4%		
SERC	Installed Capability	131,437	132,168	138,687	138,916	143,325	3.2	2.2%
	Peak Load	98,572	104,328	109,798	115,168	117,051	1.6	5.4%
	Installed Margin	32,865	27,840	28,889	23,748	26,274		
	Capacity Margin	25.0%	21.1%	20.8%	17.1%	18.3%		
MAIN	Installed Capability	44,568	[illegible],351	44,805	49,336	49,373	0.1	4.4%
	Peak Load	32,432	35,968	37,458	41,139	39,460	-4.1	4.0%
	Installed Margin	12,136	9,383	7,347	8,197	9,913		
	Capacity Margin	27.2%	20.7%	16.4%	16.6%	20.1%		
SPP	Installed Capability	62,225	65,102	66,342	66,221	66,625	0.6	2.3%
	Peak Load	45,026	47,532	47,723	49,356	49,439	0.2	2.0%
	Installed Margin	17,199	17,570	18,619	16,865	17,186		
	Capacity Margin	27.6%	27.0%	28.1%	25.5%	25.8%		
ERCOT	Installed Capability	43,829	43,386	47,476	49,227	51,927	5.5	2.8%
	Peak Load	38,062	39,140	39,339	40,843	40,402	-1.1	2.6%
	Installed Margin	5,767	4,246	8,137	8,384	11,525		
	Capacity Margin	13.2%	9.8%	17.1%	17.0%	22.2%		
MAPP	Installed Capability	28,685	28,438	28,586	30,775	30,864	0.3	2.2%
	Peak Load	19,936	21,245	23,162	24,899	24,336	-2.3	4.8%
	Installed Margin	8,749	7,193	5,424	5,876	6,528		
	Capacity Margin	30.5%	25.3%	19.0%	19.1%	21.2%		
WSCC	Installed Capability	119,417	124,140	125,819	127,402	129,533	1.7	2.6%
	Peak Load	83,119	82,301	82,967	90,551	90,657	0.1	3.1%
	Installed Margin	36,298	41,839	42,852	36,851	38,876		
	Capacity Margin	30.4%	33.7%	34.1%	28.9%	30.0%		
NERC UNITED STATES**	Installed Capability	621,597	633,291	648,118	661,580	673,316	1.8	2.3%
	Peak Load	460,503	476,320	496,185	529,460	523,432	-1.1	4.1%
	Installed Margin	161,094	156,971	151,933	132,120	149,884		
	Capacity Margin	25.9%	24.8%	23.4%	20.0%	22.3%		

* Compound annual growth rate from 1985 to 1989.

** U.S. totals are not meaningful and should not be used for policy purposes.

NOTE: For definitions of terms see page 5.

Table 2 – WINTER INSTALLED CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS (MW)

Regions		1985/86	1986/87	1987/88	1988/89	1989/90	89/88 % Chg	Growth Rate 1985–1989*
NPCC	Installed Capability	52,984	53,418	54,500	55,914	56,992	1.9	1.8%
	Peak Load	38,233	37,976	41,902	42,951	42,588	-0.8	2.7%
	Installed Margin	14,751	15,442	12,598	12,963	14,404		
	Capacity Margin	27.8%	28.9%	23.1%	23.2%	25.3%		
MAAC	Installed Capability	49,715	49,978	50,943	51,300	52,336	2.0	1.3%
	Peak Load	31,652	32,807	35,775	36,363	38,161	4.9	4.8%
	Installed Margin	18,063	17,171	15,168	14,937	14,175		
	Capacity Margin	36.3%	34.4%	29.8%	29.1%	27.1%		
ECAR	Installed Capability	95,750	96,664	98,986	98,688	99,981	1.3	1.1%
	Peak Load	65,667	64,561	68,118	68,977	73,080	5.9	2.7%
	Installed Margin	30,083	32,103	30,868	29,711	26,901		
	Capacity Margin	31.4%	33.2%	31.2%	30.1%	26.9%		
SERC	Installed Capability	134,754	135,482	140,138	143,140	145,909	1.9	2.0%
	Peak Load	97,854	101,849	105,476	108,649	121,995	12.3	5.7%
	Installed Margin	36,900	33,633	34,662	34,491	23,914		
	Capacity Margin	27.4%	24.8%	24.7%	24.1%	16.4%		
MAIN	Installed Capability	46,319	46,215	48,057	50,305	50,334	0.1	2.1%
	Peak Load	29,060	28,036	30,618	30,631	33,770	10.2	3.8%
	Installed Margin	17,259	18,179	17,439	19,674	16,564		
	Capacity Margin	37.3%	39.3%	36.3%	39.1%	32.9%		
SPP	Installed Capability	63,956	64,812	65,897	66,515	67,194	1.0	1.2%
	Peak Load	34,618	33,877	34,472	35,649	42,268	18.6	5.1%
	Installed Margin	29,338	30,935	31,425	30,866	24,926		
	Capacity Margin	45.9%	47.7%	47.7%	46.4%	37.1%		
ERCOT	Installed Capability	44,036	44,880	48,167	50,654	52,169	3.0	4.3%
	Peak Load	29,776	28,730	31,399	34,628	38,388	10.9	6.6%
	Installed Margin	14,260	16,150	16,768	16,026	13,781		
	Capacity Margin	32.4%	36.0%	34.8%	31.6%	26.4%		
MAPP	Installed Capability	29,434	29,266	30,587	31,804	31,680	-0.4	1.9%
	Peak Load	18,803	18,850	19,335	20,162	21,360	5.9	3.2%
	Installed Margin	10,631	10,416	11,252	11,642	10,320		
	Capacity Margin	36.1%	35.6%	36.8%	36.6%	32.6%		
WSCC	Installed Capability	119,527	126,006	125,702	128,620	128,654	0.0	1.9%
	Peak Load	77,997	76,171	81,182	88,523	84,768	-4.2	2.1%
	Installed Margin	41,530	49,835	44,520	40,097	43,886		
	Capacity Margin	34.7%	39.5%	35.4%	31.2%	34.1%		
NERC UNITED STATES**	Installed Capability	636,475	646,721	662,977	676,940	685,249	1.2	1.9%
	Peak Load	423,660	422,857	448,277	466,533	496,378	6.4	4.0%
	Installed Margin	212,815	223,864	214,700	210,407	188,871		
	Capacity Margin	33.4%	34.6%	32.4%	31.1%	27.6%		

* Compound annual growth rate from 1985/86 to 1989/90.

** U.S. totals are not meaningful and should not be used for policy purposes.

NOTE: For definitions of terms see page 5.

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS 1975-1989

The relationship between the summer and winter peak loads in the different regions of the country, and also for the contiguous United States, are shown in the accompanying table, where the summer peak load in each case is expressed as a percentage of the winter peak load for the following season.

In those regions where the summer peak load has been characteristically higher than the peak during the following winter, the percentage figure has, expectedly, been above 100 percent. This has been true particularly in SPP and ERCOT, where, due to climatic conditions, heavy air conditioning loads during the summer months have caused peaks that far exceed those during the following winter.

From the mid-1960s to the mid-1970s summer peaks for the country as a whole generally exceeded the peaks for the following winter by increasing amounts. In 1970, and again in 1971, apparently normal summer peaks were followed by winter peaks depressed both by mild weather and reduced industrial loads. This combination produced summer to winter peak relationships of 111 percent and 112 percent respectively in 1970 and 1971. After falling back to 110 percent in 1972, the summer/winter ratio jumped to an all-time high of 117 percent in 1973 because of the unprecedented drop in the winter peak load from the previous year. The ratio lowered only one point in 1974 since both the summer and winter peak loads were little changed from those experienced in 1973. Through the rest of the 1970s the ratio fluctuated in the more normal range of between 106 and 108 percent. The hot summer of 1980 and the economic downturn of 1981 helped to produce values of 111 and 108 percent respectively. In 1982 the summer peak dropped 3.1 percent and the winter peak dropped 4.5 percent. The greater relative decline in the winter peak caused the summer/winter ratio to increase to 111 in 1982. The national ratio dropped to 109 percent in 1983. Then, due to a rebound in the 1984/85 winter peak load, the ratio fell to 103 percent in 1984 --the lowest value registered since 1965. More normal ratios occurred in the nine regions in 1985, with the contiguous U.S. registering a value of 109 percent. In 1986 a slight decline in the winter peak, coupled with a 3.4 percent increase in the summer peak, caused the summer/winter ratio to increase to 113 percent. A lesser increase in summer than in winter 1987 peak gave a value of 111 percent. In 1988, a summer increase in peak load of 6.7 percent, and only 4.1 percent in winter, increased the ratio of difference to 113 percent. A one percent decline in the summer 1989 peak, coupled with a 6.4 percent increase in the winter peak resulted in a ratio of 105 percent.

Table 3 - SUMMER PEAK LOADS EXPRESSED AS PERCENTAGE OF PEAK LOAD FOR THE FOLLOWING WINTER

Regions	75/76	76/78	77/78	78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	87/88	88/89	89/90
NPCC	102	96	105	102	100	104	101	105	105	102	105	103	102	105	106
MAAC	114	108	115	111	114	116	109	120	115	106	117	114	113	119	109
ECAR	102	97	101	99	104	101	102	105	103	98	101	107	107	115	103
SERC	100	93	99	99	101	99	97	101	106	87	101	102	104	106	96
MAIN	119	122	122	118	123	127	121	129	123	127	112	128	122	134	117
SPP	124	144	144	139	133	147	139	132	128	130	130	140	138	138	117
ERCOT	141	142	142	134	130	132	128	131	118	115	128	136	125	118	105
MAPP	106	103	103	111	105	111	108	109	111	109	106	113	120	123	114
WSCC	104	107	107	98	100	107	105	105	98	103	107	108	102	102	107
NERC U.S	108	106	106	107	108	111	108	111	109	103	109	113	111	113	105

ANNUAL ENERGY REQUIREMENTS AND ANNUAL LOAD FACTORS, 1985–1989

The 1989 energy requirements and annual load factors by reliability council are given in Tables 4 and 5, together with corresponding information for the previous four years. Table 4 shows that during 1989 electric energy requirements for the contiguous United States amounted to 2.8 billion megawatthours--2.9 percent higher than the output for 1988. The point-to-point average annual compound increase between 1985 and 1989 for energy requirements was 3.3 percent.

As can be seen from Table 5, the 1989 annual load factor for the sum of the nine regions was 62.2 percent. This returned the load factor to its usual low 60 percent range following a dip to below 60 percent in 1988.

Table 4 – ANNUAL ENERGY REQUIREMENTS (Megawatthours in Thousands)

Regions	1985	1986	1987	1988	1989	89/88 % Inc	Growth Rate 1985–1989*
NPCC	220,782	227,865	239,063	250,132	258,700	3.4%	4.0%
MAAC	189,671	197,056	207,007	218,636	225,400	3.1%	4.4%
ECAR	387,514	390,245	408,739	429,198	437,900	2.0%	3.1%
SERC	522,648	545,409	573,735	593,948	617,400	3.9%	4.3%
MAIN	173,589	177,190	181,972	194,101	198,700	2.4%	3.4%
SPP	229,677	216,501	228,260	237,179	244,600	3.1%	1.6%
ERCOT	190,758	190,796	195,400	201,472	208,100	3.3%	2.2%
MAPP	105,797	106,824	113,063	121,737	125,400	3.0%	4.3%
WSCC	478,790	480,218	496,293	522,455	533,600	2.1%	2.7%
NERC U.S.	2,499,226	2,532,104	2,643,532	2,768,858	2,849,800	2.9%	3.3%

* Average annual growth rate from 1985 to 1989.

Table 5 – ANNUAL PERCENT LOAD FACTOR

Regions	1985	1986	1987	1988	1989
NPCC	63.0	66.7	64.0	62.9	64.4
MAAC	58.4	59.9	58.3	57.7	61.4
ECAR	66.7	64.3	64.3	61.7	66.6
SERC	60.5	59.7	59.7	58.7	60.8
MAIN	61.1	56.2	55.5	53.7	56.2
SPP	58.2	52.0	54.6	54.7	56.3
ERCOT	57.2	55.6	56.7	56.2	58.6
MAPP	60.6	57.4	55.7	55.7	57.7
WSCC	65.8	66.6	68.3	65.7	68.1
NERC U.S.	62.0	60.7	60.8	59.5	62.2

Table 6
CHANGES IN SCHEDULED OPERATION DATE OF NUCLEAR AND FOSSIL-FIRED STEAM TURBINE-GENERATORS
REMOVED FROM SCHEDULE AND DELAYED A YEAR OR MORE
BETWEEN JANUARY 1, 1989 AND JANUARY 1, 1990

Owner	Plant Name and Unit Number	Type	Nameplate Capacity MW	Net Expected Capability MW	Scheduled Operation Date as of January 1, 1989	Scheduled Operation Date as of January 1, 1990
Total Nuclear Units Removed from Schedule	None		-	-		
Long Island Lighting Co.	Shoreham No. 1	N	847	809	7-89	12-90
Texas Utilities Company System	Comanche Peak No. 2	N	1,161	1,150	6-91	6-92
Total Nuclear Units Delayed One Year or More		[2]	2,008	1,959		
Total Nuclear Units Removed from Schedule and Delayed		[2]	2,008	1,959		
Public Service Co of New Mexico	New Mexico Station No. 1	F	500	500	1999	Removed
Public Service Co of New Mexico	New Mexico Station No. 2	F	500	500	1999	Removed
Public Service Co of New Mexico	New Mexico Station No. 3	F	500	500	1999	Removed
Public Service Co of New Mexico	New Mexico Station No. 4	F	500	500	1999	Removed
Total Fossil Units Removed from Schedule		[4]	2,000	2,000		
Total Fossil Units Delayed One Year or More	None		-	-		
Total Fossil Units Removed from Schedule and Delayed		[4]	2,000	2,000		
Total Nuclear and Fossil Units Removed From Schedule and Delayed		[6]	4,008	3,959		

ADDITIONS TO ELECTRIC GENERATING CAPABILITY DURING 1989

The 1989 additions to electric generating capability in the contiguous United States are shown in the top part of Table 7 according to the type of generating units. The second portion of the table presents the same information arranged according to the reliability councils in which the new capability was installed. The third portion of the table reports the same information classified according to ownership of the new units.

Table 7 -- 1989 ADDITIONS TO ELECTRIC GENERATING CAPABILITY (In Terms of Net Expected Capabilities of the Units)

	THERMAL								HYDRAULIC					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine-Generators		Conventional		Pumped-Storage		Total	
	Nuclear		Conventional											
	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW
1989 ADDITIONS	3	3,486	4	2,874	16	934	2	12	1	6	-	-	26	7,312
ADDITIONS BY REGION														
NPCC	-	-	-	-	3	238	-	-	-	-	-	-	3	238
MAAC	-	-	-	-	4	278	2	12	-	-	-	-	6	290
ECAR	-	-	2	1,358	-	-	-	-	-	-	-	-	2	1,358
SERC	1	1,086	2	1,516	7	392	-	-	-	-	-	-	10	2,994
MAIN	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SPP	-	-	-	-	1	15	-	-	-	-	-	-	1	15
ERCOT	2	2,400	-	-	-	-	-	-	-	-	-	-	2	2,400
MAPP	-	-	-	-	-	-	-	-	-	-	-	-	-	-
WSCC	-	-	-	-	1	11	-	-	1	6	-	-	2	17
ADDITIONS BY OWNERSHIP														
Investor-Owned	3	3,486	3	2,816	12	819	-	-	-	-	-	-	18	7,121
Federal	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Municipal	-	-	1	58	3	104	2	12	1	6	-	-	7	180
Cooperative	-	-	-	-	-	-	-	-	-	-	-	-	-	-
State and Local	-	-	-	-	1	11	-	-	-	-	-	-	1	11

Table 8 - 1989 ADDITIONS TO ELECTRIC GENERATING CAPABILITY
U.S. Electric Utility Systems
Units 4,000 kW and Larger

LEGEND FOR LISTING OF PROJECTS PLACED IN SERVICE

SYMBOLS:

Investor-Owned	I
Federal	F
Municipal	M
Cooperative	C
State & Local	SL
Thermal	
Conventional steam turbine-generator	T
Nuclear steam turbine-generator	N
Combustion turbine-generator	G
Diesel engine-generator	D
Hydraulic	
Hydraulic turbine-generator	H
Pumped-Storage	
Pumped-storage turbine-generator	S
Reversible pumped-storage turbine-generator	R
Combined-Cycle	
Combustion turbine-generator for combined-cycle operation	GC
Conventional steam turbine-generator for combined-cycle operation	TC

+ Denotes multiple ownership of the unit. In such cases, the name of the participating utility system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the utility system shown is the first in alphabetical order among the major participants.

NOTE: Megawatts shown for individual generating units represent, in most cases, the net operating capability expected by the utility systems; in other cases they represent the manufacturer's nameplate rating of the unit.

Table 8 -- 1989 ADDITIONS TO ELECTRIC GENERATING CAPABILITY BY U.S. ELECTRIC UTILITY SYSTEMS

REGIONS	SYSTEM	UNIT	OWNER-SHIP	TYPE	FOSSIL FUELS	MW of NET EXPECTED CAPABILITY
NPCC	LONG ISLAND LTG CO	NEW YORK NO 1	I	G		79
NPCC	LONG ISLAND LTG CO	NEW YORK NO 2	I	G		79
NPCC	LONG ISLAND LTG CO	NEW YORK NO 3	I	G		79
MAAC	DELMARVA PR & LT CO	HAY ROAD NO 2	I	G		105
MAAC	DELMARVA PR & LT CO	HAY ROAD NO 1	I	G		105
MAAC	EASTON MARYLAND	PLANT 2 UNIT 23	M	D		6
MAAC	EASTON MARYLAND	PLANT 2 UNIT 24	M	D		6
MAAC	JERSEY CENTRAL P & L	FORKED RIVER NO 1	I	G		34
MAAC	JERSEY CENTRAL P & L	FORKED RIVER NO 2	I	G		34
ECAR	AMERICAN ELEC PR CO	ROCKPORT NO 2	I	T	Coal	1,300
ECAR	DETROIT MICHIGAN	MUNICIPAL	M	T		58
SERC	ALABAMA POWER CO	MILLER NO 3	I	T	Coal	667
SERC	FORT PIERCE FLORIDA	KING	M	G		30
SERC	+ GEORGIA POWER CO	SCHERER NO 4	I	T	Coal	849
SERC	+ GEORGIA POWER CO	VOGTLE NO 2	I	N		1,086
SERC	ORLANDO FLORIDA	INDIAN RIVER A	M	G		37
SERC	ORLANDO FLORIDA	INDIAN RIVER B	M	G		37
SERC	VIRGINIA ELECTRIC	GRAVEL NECK NO 3	I	G		72
SERC	VIRGINIA ELECTRIC	GRAVEL NECK NO 4	I	G		72
SERC	VIRGINIA ELECTRIC	GRAVEL NECK NO 5	I	G		72
SERC	VIRGINIA ELECTRIC	GRAVEL NECK NO 6	I	G		72
SPP	ST JOSEPH LT & PR CO	LAKE ROAD UT GT	I	G		15
ERCOT	+ HOUSTON LTG & PR CO	SOUTH TEXAS NO 2	I	N		1,250
ERCOT	+ TEXAS UTIL CO SYS	COMANCHE PEAK NO 1	I	N		1,150
WSCC	SANTA CLARA CALIF	BLACK BUTTE DAM	M	H		6
WSCC	VERNON CALIFORNIA	COMBUSTION TURBINE	SL	G		11

26 GENERATING UNITS WERE ADDED WITH TOTAL NET EXPECTED CAPABILITY OF 7,312 MW

NUCLEAR ELECTRIC POWER GENERATING UNITS IN COMMERCIAL OPERATION

No steam turbine-generators for nuclear projects have been ordered since 1976, and no nuclear steam supply systems (reactors) since 1978. As of January 1, 1990, nuclear capacity accounts for 39 percent of the aggregate of the industry's scheduled expansion program.

Table 9 shows subtotals of the amount of nuclear megawatts placed in service each year. As of January 1, 1990, there were 111 nuclear units in commercial operation with an aggregate winter rating of 99,278 megawatts. There were three additions to nuclear generating capacity during 1989. Two decommisioned units were removed from the list last year.

Table 9 - NUCLEAR POWER UNITS IN OPERATION IN THE CONTIGUOUS U.S. as of January 1, 1990

	SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMML OPTN	CAPABILITY (MW) SUMMER	CAPABILITY (MW) WINTER	ANN SUBTTLS OF SUMMER MW RATINGS
1.	Yankee Atomic Electric Company	Yankee Rowe	1961	175	176	175
2.	Consumers Power Company	Big Rock Point	1962	63	63	63
3.	Conn Yankee Atomic Power Company	Haddam Neck	1968	555	580	
4.	SoCal Edison & San Diego G & E Co.	San Onofre No. 1	1968	436	436	991
5.	GPU Nuclear Corporation	Oyster Creek No. 1	1969	620	650	
6.	Niagara Mohawk Power Corp.	Nine Mile Point No. 1	1969	610	610	
7.	Rochester Gas & Electric Corp.	R. E. Ginna	1969	470	470	1,700
8.	Northeast Utilities	Millstone Point No. 1	1970	654	660	
9.	Wisconsin Electric Power Company	Point Beach No. 1	1970	495	495	1,149
10.	Carolina Power & Light Company	H. B. Robinson	1971	665	700	
11.	Commonwealth Edison Company	Dresden No. 2	1971	772	794	
12.	Northern States Power Company	Monticello No. 1	1971	536	557	1,973
13.	Boston Edison Company	Pilgrim No. 1	1972	670	670	
14.	Commonwealth Edison Company	Quad Cities No. 1	1972	768	789	
15.	Commonwealth Edison Company	Quad Cities No. 2	1972	769	789	
16.	Florida Power & Light Company	Turkey Point No. 3	1972	666	696	
17.	Maine Yankee Atomic Power Company	Maine Yankee	1972	814	830	
18.	Vermont Yankee N. Power Corp.	Vermont Yankee	1972	496	528	
19.	Virginia Electric & Power Company	Surry No. 1	1972	775	775	4,958
20.	Commonwealth Edison Company	Dresden No. 3	1973	773	794	
21.	Consumers Power Company	Palisades No. 1	1973	635	740	
22.	Duke Power Company	Oconee No. 1	1973	860	860	
23.	Duke Power Company	Oconee No. 2	1973	860	860	
24.	Florida Power & Light Company	Turkey Point No. 4	1973	666	696	
25.	Northern States Power Company	Prairie Island No. 1	1973	503	523	
26.	Omaha Public Power District	Fort Calhoun No. 1	1973	439	457	
27.	Tennessee Valley Authority	Browns Ferry No. 1	1973	1,067	1,067	
28.	Virginia Electric & Power Company	Surry No. 2	1973	775	775	
29.	Wisconsin Electric Power Company	Point Beach No. 2	1973	495	495	7,073
30.	Arkansas Power & Light Company	Arkansas Nuclear No. 1	1974	836	836	
31.	Commonwealth Edison Company	Zion No. 1	1974	1,040	1,040	
32.	Commonwealth Edison Company	Zion No. 2	1974	1,040	1,040	
33.	Consolidated Edison Co. of NY	Indian Point No. 2	1974	849	864	
34.	Duke Power Company	Oconee No. 3	1974	860	860	

Table 9 – NUCLEAR POWER UNITS IN OPERATION IN THE CONTIGUOUS U.S. as of January 1, 1990 -- Cont'd.

	SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMML OPTN	CAPABILITY (MW) SUMMER	CAPABILITY (MW) WINTER	ANN SUBTTLS OF SUMMER MW RATINGS
36.	Iowa Electric Light & Power Co.	Duane Arnold	1974	480	510	
37.	Nebraska Public Power District	Cooper	1974	778	778	
38.	Northern States Power Company	Prairie Island No. 2	1974	500	520	
39.	Philadelphia Electric Company	Peach Bottom No. 2	1974	1,051	1,055	
40.	Philadelphia Electric Company	Peach Bottom No. 3	1974	1,035	1,035	
41.	Wisconsin Public Service Corp.	Kewaunee No. 1	1974	525	517	9,770
42.	Baltimore Gas & Electric Company	Calvert Cliffs No. 1	1975	810	820	
43.	Carolina Power & Light Company	Brunswick No. 2	1975	790	790	
44.	Georgia Power Company	Hatch No. 1	1975	771	771	
45.	Indiana & Michigan Electric Co.	D. C. Cook No. 1	1975	1,050	1,050	
46.	New York Power Authority	J. A. Fitzpatrick	1975	821	821	
47.	Sacramento Utility District	Rancho Seco No. 1	1975	875	903	
48.	Tennessee Valley Authority	Browns Ferry No. 2	1975	1,067	1,067	6,184
49.	Duquesne Light Company	Beaver Valley No. 1	1976	800	800	
50.	Florida Power & Light Company	St. Lucie No. 1	1976	777	795	
51.	New York Power Authority	Indian Point No. 3	1976	965	965	
52.	Northeast Utilities	Millstone Point No. 2	1976	864	864	
53.	Portland General Electric Company	Trojan	1976	1,080	1,080	4,486
54.	Alabama Power Company	J. M. Farley No. 1	1977	807	807	
55.	Baltimore Gas & Electric Company	Calvert Cliffs No. 2	1977	825	860	
56.	Carolina Power & Light Company	Brunswick No. 1	1977	790	790	
57.	Florida Power Corporation	Crystal River No. 3	1977	782	807	
58.	Public Service Elec & Gas Company	Salem No. 1	1977	1,079	1,100	
59.	Tennessee Valley Authority	Browns Ferry No. 3	1977	1,067	1,067	
60.	Toledo Edison Company	Davis-Besse No. 1	1977	906	906	6,256
61.	Indiana & Michigan Electric Co.	D. C. Cook No. 2	1978	1,100	1,100	
62.	Virginia Electric & Power Company	North Anna No. 1	1978	898	907	1,998
63.	Georgia Power Company	Hatch No. 2	1979	771	771	
64.	Public Service Co. of Colorado	Fort St. Vrain	1979	200	200	971
65.	Arkansas Power & Light Company	Arkansas Nuclear No. 2	1980	858	858	
66.	Virginia Electric & Power Company	North Anna No. 2	1980	870	870	1,728
67.	Alabama Power Company	J. M. Farley No. 2	1981	812	812	
68.	Duke Power Company	McGuire No. 1	1981	1,180	1,180	
69.	Public Service Elec & Gas Company	Salem No. 2	1981	1,106	1,120	
70.	Tennessee Valley Authority	Sequoyah No. 1	1981	1,128	1,128	4,226
71.	Tennessee Valley Authority	Sequoyah No. 2	1982	1,148	1,148	1,148
72.	Florida Power & Light Company	St. Lucie No. 2	1983	802	802	
73.	Pennsylvania Power & Light Company	Susquehanna No. 1	1983	1,050	1,050	
74.	SoCal Edison & San Diego G & E	San Onofre No. 2	1983	1,070	1,070	2,922

Table 9 – NUCLEAR POWER UNITS IN OPERATION IN THE CONTIGUOUS U.S. as of January 1, 1990 -- Cont'd.

	SYSTEM	UNIT NAME & NO.	YEAR PLACED IN COMML OPTN	CAPABILITY (MW) SUMMER	CAPABILITY (MW) WINTER	ANN SUBTTLS OF SUMMER MW RATINGS
75.	Commonwealth Edison Company	LaSalle County No. 1	1984	1,048	1,078	
76.	Commonwealth Edison Company	LaSalle County No. 2	1984	1,048	1,078	
77.	Duke Power Company	McGuire No. 2	1984	1,150	1,150	
78.	SoCal Edison & San Diego G & E Co.	San Onofre No. 3	1984	1,080	1,080	
79.	South Carolina Electric & Gas Co.	Summer No. 1	1984	885	885	
80.	Union Electric Company	Callaway No. 1	1984	1,109	1,123	
81.	Washington Pub Power Supply System	WPPSS No. 2	1984	1,100	1,100	7,420
82.	Commonwealth Edison Company	Byron No. 1	1985	1,120	1,120	
83.	Duke Power Company	Catawba No. 1	1985	1,145	1,145	
84.	Kansas Gas & Electric Company	Wolf Creek No. 1	1985	1,150	1,150	
85.	Louisiana Power & Light Company	Waterford No. 3	1985	1,104	1,104	
86.	Mississippi Power & Light Company	Grand Gulf No. 1	1985	1,250	1,250	
87.	Pacific Gas & Electric Company	Diablo Canyon No. 1	1985	1,073	1,073	
88.	Pennsylvania Power & Light Company	Susquehanna No. 2	1985	1,050	1,050	7,892
89.	Arizona Public Service Company	Palo Verde No. 1	1986	1,270	1,270	
90.	Arizona Public Service Company	Palo Verde No. 2	1986	1,270	1,270	
91.	Duke Power Company	Catawba No. 2	1986	1,145	1,145	
92.	Gulf States Utilities Company	River Bend No. 1	1986	937	937	
93.	Northeast Utilities	Millstone Point No. 3	1986	1,142	1,150	
94.	Pacific Gas & Electric Company	Diablo Canyon No. 2	1986	1,105	1,105	
95.	Philadelphia Electric Company	Limerick No. 1	1986	1,055	1,065	
96.	Public Service Electric & Gas Co.	Hope Creek No. 1	1986	1,014	1,014	8,938
97.	Carolina Power & Light Company	Shearon Harris No. 1	1987	860	860	
98.	Cleveland Electric Illuminating Co.	Perry No. 1	1987	1,183	1,205	
99.	Commonwealth Edison Company	Braidwood No. 1	1987	1,090	1,120	
100.	Commonwealth Edison Company	Byron No. 2	1987	1,120	1,120	
101.	Duquesne Light Company	Beaver Valley No. 2	1987	820	833	
102.	Georgia Power Company	Vogtle No. 1	1987	1,086	1,086	
103.	Illinois Power Company	Clinton No. 1	1987	933	944	7,092
104.	Arizona Public Service Company	Palo Verde No. 3	1988	1,270	1,270	
105.	Commonwealth Edison Company	Braidwood No. 2	1988	1,090	1,120	
106.	Detroit Edison Company	Enrico Fermi No. 2	1988	1,093	1,093	
107.	Houston Lighting & Power Company	South Texas No. 1	1988	1,250	1,250	
108.	Niagara Mohawk Power Corp.	Nine Mile Point No. 2	1988	1,080	1,080	5,783
109.	Georgia Power Company	Vogtle No. 2	1989	1,086	1,086	
110.	Houston Lighting & Power Company	South Texas No. 2	1989	1,250	1,250	
111.	Texas Electric Utilities Company	Comanche Peak No. 1	1989	1,150	1,150	3,486
		111 Nuclear units totaling		98,382	99,278	

PART II. ELECTRIC POWER SUPPL 1990-1999

SUMMER CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

Summer peak capabilities, peak loads, and percent capacity margins as now forecast for the years 1990 through 1999 are shown in Table 10, page 19. Similar information for winter is shown in Table 11, page 21.

SUMMER CAPABILITIES

Preliminary figures published in the 1989 POST-SUMMER ELECTRIC POWER SURVEY indicated that the 1989 capability at time of summer peak was 1.2 percent above 1988. According to final data now available, the actual increase was 1.8 percent.

The overall pattern of the newly projected summer capability values generally shows tiny increases in the near years and increases of up to 2 percent in the more distant years when compared with the projections for the same years 12 months ago. For the nine regions taken together, 1990 shows an increase of 0.6 percent, rising to an increase of 2.0 percent in 1998.

The 1999 summer capability for the sum of the nine regions is projected at 761.4 thousand megawatts. This represents an average annual increase of 1.2 percent between the first and tenth forecast years.

SUMMER PEAK LOADS

Summer peak load forecasts have been increased by all reliability councils except NPCC.

For the nine regions taken together, peak loads range from 1.0 percent higher for 1990 to 1.8 percent higher in the four later years, compared with values shown for those years in the 1989 ELECTRIC POWER ANNUAL REPORT. The summer peak load for the sum of the nine regions, which was 523.4 thousand megawatts in 1989, is projected to be 539.3 thousand megawatts in 1990, an increase of 3.0 percent. For the summer of 1999, the projection is 645.9 thousand megawatts. This represents an average annual increase of 2.0 percent between the first and tenth forecast years.

SUMMER PERCENT CAPACITY MARGINS

Of the 81 summer capacity margin percentages shown for the nine-year period 1990-1998 for the nine reliability councils, 53 of the values are lower than the equivalent respective values one year previous, and only 28 of the percent margins are higher. MAIN and SPP show higher percent margins throughout most of the period. Summer percent capacity margins for the country as a whole are all lower except for 1998. As now forecast, the summer capacity margins for the country range from 21.2 percent in 1990 to 15.6 percent in 1998, shown in these reports for the first time.

Table 10 – SUMMER CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS -- 1990–1999 PROJECTED (Megawatts)

Regions		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Growth Rate 1990–1999*
NPCC	Capability	57,480	58,383	60,728	61,685	62,238	63,151	63,653	64,413	64,898	65,564	1.5%
	Peak Load	47,001	47,832	49,046	50,261	51,438	52,476	53,414	54,307	55,253	56,321	2.0%
	Installed Margin	10,479	10,551	11,682	11,424	10,800	10,675	10,239	10,106	9,645	9,243	
	% Capacity Margin	18.2%	18.1%	19.2%	18.5%	17.4%	16.9%	16.1%	15.7%	14.9%	14.1%	
MAAC	Capability	51,194	53,573	54,511	55,308	56,410	57,092	57,882	58,417	59,015	59,859	1.8%
	Peak Load	42,735	43,519	44,269	44,930	45,585	46,207	46,809	47,432	48,004	48,624	1.4%
	Installed Margin	8,459	10,054	10,242	10,378	10,825	10,885	11,073	10,985	11,011	11,235	
	% Capacity Margin	16.5%	18.8%	18.8%	18.8%	19.2%	19.1%	19.1%	18.8%	18.7%	18.8%	
ECAR	Capability	99,505	101,197	101,935	102,586	103,404	104,403	105,468	106,758	107,114	107,475	0.9%
	Peak Load	78,913	80,376	81,870	83,088	84,332	85,708	87,088	88,505	89,898	91,251	1.6%
	Installed Margin	20,592	20,821	20,065	19,498	19,072	18,695	18,380	18,253	17,216	16,224	
	% Capacity Margin	20.7%	20.6%	19.7%	19.0%	18.4%	17.9%	17.4%	17.1%	16.1%	15.1%	
SERC	Capability	145,047	147,554	151,313	153,951	157,511	162,418	166,585	170,107	174,535	176,370	2.2%
	Peak Load	121,636	125,177	129,869	133,679	136,962	140,907	144,577	148,183	151,701	154,983	2.7%
	Installed Margin	23,411	22,377	21,444	20,272	20,549	21,511	22,008	21,924	22,834	21,387	
	% Capacity Margin	16.1%	15.2%	14.2%	13.2%	13.0%	13.2%	13.2%	12.9%	13.1%	12.1%	
MAIN	Capability	49,182	49,203	49,322	49,623	50,036	50,343	50,641	51,082	51,366	52,145	0.7%
	Peak Load	39,191	39,871	40,514	41,140	41,788	42,473	43,176	43,873	44,670	45,438	1.7%
	Installed Margin	9,991	9,332	8,808	8,483	8,248	7,870	7,465	7,209	6,696	6,707	
	% Capacity Margin	20.3%	19.0%	17.9%	17.1%	16.5%	15.6%	14.7%	14.1%	13.0%	12.9%	
SPP	Capability	67,460	67,835	68,038	68,367	68,432	68,624	69,180	69,839	70,437	71,235	0.6%
	Peak Load	51,030	52,050	53,000	53,777	54,797	55,954	57,092	58,180	59,275	60,404	1.9%
	Installed Margin	16,430	15,785	15,030	14,590	13,635	12,670	12,088	11,659	11,162	10,831	
	% Capacity Margin	24.4%	23.3%	22.1%	21.3%	19.9%	18.5%	17.5%	16.7%	15.8%	15.2%	
ERCOT	Capability	53,560	53,124	54,472	54,576	54,754	55,065	56,006	57,268	57,954	60,187	1.3%
	Peak Load	41,880	42,717	44,452	45,355	46,020	46,919	48,196	49,436	50,688	52,171	2.5%
	Installed Margin	11,680	10,407	10,020	9,221	8,734	8,146	7,810	7,832	7,266	8,016	
	% Capacity Margin	21.8%	19.6%	18.4%	16.9%	16.0%	14.8%	13.9%	13.7%	12.5%	13.3%	
MAPP	Capability	31,335	31,456	31,333	31,461	31,611	31,691	31,765	31,916	32,396	32,511	0.4%
	Peak Load	24,754	25,211	25,515	25,923	26,285	26,653	27,056	27,532	27,986	28,454	1.6%
	Installed Margin	6,581	6,245	5,818	5,538	5,326	5,038	4,709	4,384	4,410	4,057	
	% Capacity Margin	21.0%	19.9%	18.6%	17.6%	16.8%	15.9%	14.8%	13.7%	13.6%	12.5%	
WSCC	Capability	126,478	127,523	128,678	129,567	130,321	131,472	132,927	133,781	135,078	136,058	0.8%
	Peak Load	92,168	93,911	95,567	97,355	99,165	101,123	103,021	104,704	106,505	108,267	1.8%
	Installed Margin	34,310	33,612	33,111	32,212	31,156	30,349	29,906	29,077	28,573	27,791	
	% Capacity Margin	27.1%	26.4%	25.7%	24.9%	23.9%	23.1%	22.5%	21.7%	21.2%	20.4%	
NERC UNITED STATES**	Capability	681,241	689,848	700,330	707,124	714,717	724,259	734,107	743,581	752,793	761,404	1.2%
	Peak Load	539,308	550,664	564,110	575,508	– 586,372	598,420	610,429	622,152	633,980	645,913	2.0%
	Installed Margin	141,933	139,184	136,220	131,616	128,345	125,839	123,678	121,429	118,813	115,491	
	% Capacity Margin	20.8%	20.2%	19.5%	18.6%	18.0%	17.4%	16.8%	16.3%	15.8%	15.2%	

* Compound annual growth rate from 1990 to 1999.

** U.S. totals are not meaningful and should not be used for policy purposes

NOTE: For definitions of terms see page 5.

Capability equals NERC's "Planned Resources" series

WINTER CAPABILITIES, PEAK LOADS, AND PERCENT CAPACITY MARGINS

WINTER CAPABILITIES

Winter 1990/91 capability now projected for the entire electric utility industry is 696.4 thousand megawatts. The regional winter capability values shown in this report for 1990/91 through 1998/99 are from one to two and one-half percent higher than those projected one year ago. ERCOT, MAPP, and WSCC are the only reliability councils showing a preponderance of reductions in their winter capability projections.

For winter 1999/2000 the total capability of the industry is projected to reach 779.0 thousand megawatts. This value yields an average annual compound growth rate of 1.3 percent between the first and tenth forecast years.

The scheduled additions table on page 25 summarizes the number and aggregate ratings of planned electric generating units that as of January 1, 1990 had been both ordered from the equipment manufacturers and placed in the expansion program by being assigned official scheduled dates of commercial operation by the utilities. As of the turn of 1989/90, the furthest out year for which an ordered unit had been scheduled for operation was 2001.

WINTER PEAK LOADS

As now projected, the winter 1990/91 peak load for the contiguous U.S. is expected to be 489.9 thousand megawatts, a decrease of 1.3 percent below the winter 1989/90 peak load. The new projections for eight of the nine regions show increased values throughout the period. NPCC is the only region that decreased its winter peak load projections. The total of the nine regions shows increases in the range of 0.9 to 1.2 percent above the winter peak loads expected for these years twelve months ago.

For winter 1999/2000, the furthest out year projected in this report, the expected peak load is 591.7 thousand megawatts. This represents an average annual increase of 2.1 percent between the first and tenth forecast years.

WINTER PERCENT CAPACITY MARGINS

Compared with projected percent capacity margin values calculated on the same basis one year ago, MAIN, ERCOT, MAPP and WSCC winter percent margins reported in this survey are generally lower. The other five regions all show increased margins. For the country as a whole, percent capacity margins are now projected to range from 29.6 percent for the winter of 1990/91 to 24.0 percent for 1999/2000.

Table 11 – WINTER CAPABILITIES, PEAK LOADS, INSTALLED MARGINS & PERCENT CAPACITY MARGINS -- 1990–1999 PROJECTED (Megawatts)

Regions		1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/2000	Growth Rate 1990–1999*
NPCC	Capability	60,009	61,835	63,028	63,818	64,739	65,244	65,746	66,431	66,974	67,601	1.3%
	Peak Load	45,070	45,774	46,739	47,595	48,487	49,356	50,144	50,970	51,940	52,950	1.8%
	Installed Margin	14,939	16,061	16,289	16,223	16,252	15,888	15,602	15,461	15,034	14,651	
	% Capacity Margin	24.9%	26.0%	25.8%	25.4%	25.1%	24.4%	23.7%	23.3%	22.4%	21.7%	
MAAC	Capability	53,844	56,386	57,482	57,718	59,181	60,042	61,002	61,674	62,437	63,416	1.8%
	Peak Load	37,825	38,767	39,731	40,631	41,512	42,298	43,134	43,905	44,698	45,423	2.1%
	Installed Margin	16,019	17,619	17,751	17,087	17,669	17,744	17,868	17,769	17,739	17,993	
	% Capacity Margin	29.8%	31.2%	30.9%	29.6%	29.9%	29.6%	29.3%	28.8%	28.4%	28.4%	
ECAR	Capability	101,383	102,963	103,804	104,765	105,479	106,330	107,736	108,576	109,100	109,434	0.9%
	Peak Load	74,455	75,846	77,051	78,219	79,373	80,788	82,055	83,345	84,617	85,756	1.6%
	Installed Margin	26,928	27,117	26,753	26,546	26,106	25,542	25,681	25,231	24,483	23,678	
	% Capacity Margin	26.6%	26.3%	25.8%	25.3%	24.7%	24.0%	23.8%	23.2%	22.4%	21.6%	
SERC	Capability	148,225	151,752	154,819	158,297	162,034	165,878	170,960	175,291	178,884	181,162	2.3%
	Peak Load	117,810	121,530	125,234	128,910	132,606	136,225	139,823	143,239	146,735	150,196	2.7%
	Installed Margin	30,415	30,222	29,585	29,387	29,428	29,653	31,137	32,052	32,149	30,966	
	% Capacity Margin	20.5%	19.9%	19.1%	18.6%	18.2%	17.9%	18.2%	18.3%	18.0%	17.1%	
MAIN	Capability	50,147	50,161	50,287	50,607	51,051	51,376	51,704	52,145	52,445	53,243	0.7%
	Peak Load	32,117	32,733	33,250	33,875	34,512	35,126	35,754	36,421	37,124	37,761	1.8%
	Installed Margin	18,030	17,428	17,037	16,732	16,539	16,250	15,950	15,724	15,321	15,482	
	% Capacity Margin	36.0%	34.7%	33.9%	33.1%	32.4%	31.6%	30.8%	30.2%	29.2%	29.1%	
SPP	Capability	67,805	68,168	68,371	68,748	68,785	69,089	69,793	70,424	71,044	71,522	0.6%
	Peak Load	38,731	39,447	40,187	41,025	41,946	42,981	43,954	44,911	45,858	46,832	2.1%
	Installed Margin	29,074	28,721	28,184	27,723	26,839	26,108	25,839	25,513	25,186	24,690	
	% Capacity Margin	42.9%	42.1%	41.2%	40.3%	39.0%	37.8%	37.0%	36.2%	35.5%	34.5%	
ERCOT	Capability	53,527	53,391	54,843	54,721	54,653	55,423	57,110	57,549	59,178	60,512	1.4%
	Peak Load	34,059	35,633	36,635	37,394	38,248	39,419	40,596	41,777	43,109	44,444	3.0%
	Installed Margin	19,468	17,758	18,208	17,327	16,405	16,004	16,514	15,772	16,069	16,068	
	% Capacity Margin	36.4%	33.3%	33.2%	31.7%	30.0%	28.9%	28.9%	27.4%	27.2%	26.6%	
MAPP	Capability	31,992	32,125	32,108	32,248	32,408	32,514	32,608	32,758	33,307	33,401	0.5%
	Peak Load	21,087	21,511	21,892	22,207	22,547	22,898	23,299	23,711	24,110	24,573	1.7%
	Installed Margin	10,905	10,614	10,216	10,041	9,861	9,616	9,309	9,047	9,197	8,828	
	% Capacity Margin	34.1%	33.0%	31.8%	31.1%	30.4%	29.6%	28.5%	27.6%	27.6%	26.4%	
WSCC	Capability	129,453	129,811	131,301	132,235	133,492	134,386	135,922	136,728	138,060	138,736	0.8%
	Peak Load	88,754	90,173	92,277	93,555	95,278	97,014	98,721	100,290	102,001	103,767	1.8%
	Installed Margin	40,699	39,638	39,024	38,680	38,214	37,372	37,201	36,438	36,059	34,969	
	% Capacity Margin	31.4%	30.5%	29.7%	29.3%	28.6%	27.8%	27.4%	26.6%	26.1%	25.2%	
NERC UNITED STATES**	Capability	696,385	706,592	716,043	723,157	731,822	740,282	752,581	761,576	771,429	779,027	1.3%
	Peak Load	489,908	501,414	512,996	523,411	534,509	546,105	557,480	568,569	580,192	591,702	2.1%
	Installed Margin	206,477	205,178	203,047	199,746	197,313	194,177	195,101	193,007	191,237	187,325	
	% Capacity Margin	29.6%	29.0%	28.4%	27.6%	27.0%	26.2%	25.9%	25.3%	24.8%	24.0%	

* Compound annual growth rate from 1989/90 to 1999/2000

** U.S. totals are not meaningful and should not be used for policy purposes.

NOTE: For definitions of terms see page 5.

Capability equals NERC's "Planned Resources" series

RELATIONSHIP BETWEEN SUMMER AND WINTER PEAK LOADS, 1990–1999

The relationship between the summer and winter peak loads in the different regions of the country, and also for the sum of the U.S. portions of the NERC regions, are shown in the accompanying table, where the summer peak load in case is expressed as a percentage of the winter peak load for the following season.

Though there are some changes from year to year in the regional ratios, the movements are generally offsetting to the extent that the summer/winter ratio for the sum of the nine regions calculates to either 110 percent or 109 percent throughout the ten–year period.

Table 12 – SUMMER PEAK LOADS AS PERCENT OF PEAK LOADS FOR THE FOLLOWING WINTER, 1990–1999

Regions	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	99/2000
NPCC	104	104	105	106	106	106	107	107	106	106
MAAC	113	112	111	111	110	109	109	108	107	107
ECAR	106	106	106	106	106	106	106	106	106	106
SERC	103	103	104	104	103	103	103	103	103	103
MAIN	122	122	122	121	121	121	121	120	120	120
SPP	132	132	132	131	131	130	130	130	129	129
ERCOT	123	120	121	121	120	119	119	118	118	117
MAPP	117	117	117	117	117	116	116	116	116	116
WSCC	104	104	104	104	104	104	104	104	104	104
NERC U.S.	110	110	110	110	110	110	109	109	109	109

Table 13 – ANNUAL PERCENT LOAD FACTORS, 1990–1999

Regions	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
NPCC	62.5	62.7	62.5	62.2	61.9	61.7	61.4	61.4	61.4	61.3
MAAC	59.9	61.0	61.2	61.7	62.0	62.2	62.3	62.7	63.0	63.1
ECAR	64.8	64.9	64.6	64.7	64.6	64.5	64.4	64.5	64.4	64.4
SERC	60.2	60.4	59.6	59.6	59.7	59.7	59.5	59.6	59.7	59.7
MAIN	56.8	56.9	56.8	57.0	57.1	57.2	57.2	57.5	57.5	57.6
SPP	54.7	54.7	54.6	54.7	54.9	54.9	54.9	55.2	55.3	55.3
ERCOT	56.1	56.9	56.6	57.2	57.5	57.7	57.7	58.1	58.2	58.3
MAPP	57.9	58.0	58.3	58.6	58.9	59.0	59.1	59.4	59.5	59.6
WSCC	67.9	67.9	68.0	68.2	67.9	67.8	67.6	67.8	67.8	67.7
NERC U.S.	61.2	61.4	61.2	61.3	61.3	61.3	61.2	61.4	61.4	61.4

ANNUAL ENERGY REQUIREMENTS AND ANNUAL PERCENT LOAD FACTORS FOR 1990–1999

Calendar–year energy requirements by NERC region and for the sum of the U.S. portions of the NERC regions are shown in Table 14. The corresponding annual load factors are given in Table 13. The energy requirement represents utility generation plus megawatthours received from all outside sources, including net imports from other countries and energy from certain industrial installations which are interconnected and coordinated with the utility systems.

The present projections of energy requirements for the contiguous United States for the years 1990 through 1998 range between 0.9 and 1.8 percent above the values predicted in the 1988 ELECTRIC POWER ANNUAL REPORT. SERC raised its energy projections the most, between 2.0 and 3.7 percent higher over the period. MAPP projections were 2.2 to 3.2 percent higher, ECAR 1.9 to 2.7 percent higher, MAIN 0.4 to 1.1 percent higher. MAAC was 0.3 to 2.4 percent higher, SPP 0.4 to 0.7 percent higher, and WSCC 0.2 to 1.4 higher. NPCC was the only region showing consistent reductions, ranging from 0.8 percent lower in 1993 to 1.4 percent lower in 1997. ERCOT's changes range from a 0.4 percent reduction in 1990 to 2.8 percent increases in the late 90s. For 1999, the new furthest out year, the projected megawatthour requirement is 3.5 billion megawatthours. This represents an average annual increase of 2.1 percent between the first and tenth forecast years.

Table 14 ANNUAL ENERGY REQUIREMENTS (Megawatthours in Thousands) -- 1990–1999

Regions	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	Growth Rate 1990–1999*
NPCC	257,394	262,682	269,089	273,910	278,849	283,513	288,134	292,259	297,084	302,517	1.8%
MAAC	224,159	232,405	237,931	242,790	247,484	251,799	256,201	260,530	264,728	268,956	2.0%
ECAR	447,644	456,863	464,675	470,626	477,081	484,596	492,468	499,849	507,164	514,586	1.6%
SERC	641,920	661,889	679,480	698,171	716,603	736,870	755,500	774,009	792,919	810,337	2.6%
MAIN	195,145	198,701	201,986	205,410	209,134	212,965	216,954	220,983	225,087	229,193	1.8%
SPP	244,330	249,593	254,077	257,898	263,404	269,262	275,221	281,129	286,972	292,820	2.0%
ERCOT	205,819	212,854	221,175	227,236	231,673	237,270	244,485	251,514	258,569	266,642	2.9%
MAPP	125,476	128,083	130,637	133,068	135,547	137,792	140,429	143,158	145,822	148,643	1.9%
WSCC	547,970	558,510	571,042	581,454	590,247	600,741	612,117	621,815	632,829	642,311	1.8%
NERC U.S.	2,889,857	2,961,580	3,030,092	3,090,563	3,150,022	3,214,808	3,281,509	3,345,246	3,411,174	3,476,005	2.1%

* Average annual growth rate from 1990 to 1999

FUTURE EXPANSION PROGRAM AND SCHEDULED STEAM TURBINE-GENERATOR ADDITIONS BY SIZE

Table 16 shows that as of January 1, 1990, the electric utility systems serving the contiguous United States had on order with both domestic and foreign manufacturers, and scheduled for commercial operation during 1990 and later years, a total of 29.4 thousand megawatts. This included ten hydro units of both conventional and pumped-storage type, totaling 1.4 thousand megawatts. The thermal units include ten nuclear steam turbine-generators, twenty-five conventional steam turbine-generators, and seventy-three combustion turbine-generators. Some of this capacity is on site and being installed; the remainder is under manufacture or in the form of firm orders.

During 1990, 3 nuclear power units are scheduled for commercial operation. These 3 units have an aggregate capability of 3.0 thousand megawatts. As of January 1, 1990, there are 7 additional nuclear units on order and scheduled for commercial operation in 1991 and later in the contiguous United States, having an aggregate capability of 8.4 thousand megawatts. These units are included in the regional listing designated Table 17. An indeterminate number of units, amounting to several thousand megawatts, are also on order but are either awaiting their first assignment of a scheduled date of commercial operation by the utility systems, or were once scheduled and have since been removed from the expansion program. It is probable that the majority of the orders in the second category (being held open as options by the manufacturers) will not be reactivated.

Table 15 shows that, of the total 21.9 thousand megawatts of steam turbine-generators on order as of January 1, 1990, and scheduled for service, nuclear and conventional units in sizes 700 megawatts and larger account for 68.5 percent of the total. The units in the less than 100 megawatt range are comprised of seven conventional steam turbine-generators with a total capability of 307 megawatts, four of which are for combined-cycle operation.

Table 15 – NUMBER AND AGGREGATE CAPABILITY OF STEAM TURBINE-GENERATORS IN THE EXPANSION PROGRAM GROUPED ACCORDING TO SIZE RANGE as of January 1, 1990

Size Range, MW	No. Of Units	Aggregate Capability MW	Percent of Total
1,300 MW and Larger	1	1,300	5.9
1,200 to 1,299	4	4,916	22.5
1,100 to 1,199	4	4,654	21.3
1,000 to 1,099	1	1,055	4.8
900 to 999	–	--	–
800 to 899	1	809	3.7
700 to 799	3	2,250	10.3
600 to 699	5	3,197	14.6
500 to 599	1	500	2.3
400 to 499	4	1,878	8.6
300 to 399	1	360	1.7
200 to 299	1	250	1.1
100 to 199	2	298	1.4
Under 100	7	307	1.8
TOTAL STEAM UNITS	35	21,854	100.0

Table 16 SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPABILITY
BASED ON SCHEDULED DATES OF COMMERCIAL OPERATION AS OF JANUARY 1, 1990
In Terms of Net Expected Capability Ratings of the Units in Megawatts

	THERMAL								HYDRAULIC					
	Steam Turbine-Generators				Combustion Turbine-Generators		Diesel Engine-Generators		Conventional		Pumped-Storage		Total	
	Nuclear		Conventional											
	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW	No. of Units	MW
TOTAL SCHEDULED	10	11,434	25	10,420	73	6,059	4	32	6	415	4	1,000	122	29,360
SCHEDULED ADDITIONS BY YEAR														
1990	3	3,014	4	578	20	1,170	2	12	2	25	-	-	31	4,799
1991	1	1,177	6	3,501	10	666	2	20	-	-	-	-	19	5,364
1992	1	1,150	2	556	7	640	-	-	4	390	2	500	16	3,236
1993	-	-	4	570	10	1,236	-	-	-	-	2	500	16	2,306
1994	1	1,177	2	840	7	663	-	-	-	-	-	-	10	2,680
1995	-	-	1	750	10	848	-	-	-	-	-	-	11	1,598
1996	-	-	1	645	8	709	-	-	-	-	-	-	9	1,354
1997	1	1,213	1	750	-	-	-	-	-	-	-	-	2	1,963
1998	-	-	2	1,130	1	127	-	-	-	-	-	-	3	1,257
1999	3	3,703	1	500	-	-	-	-	-	-	-	-	4	4,203
2001	-	-	1	600	-	-	-	-	-	-	-	-	1	600
SCHEDULED ADDITIONS BY REGION														
NPCC	2	1,959	3	330	8	680	-	-	2	25	-	-	15	2,994
MAAC	1	1,055	1	640	9	825	-	-	-	-	-	-	11	2,520
ECAR	-	-	3	2,395	7	543	-	-	-	-	-	-	10	2,938
SERC	4	4,780	6	1,695	27	2,390	2	20	-	-	4	1,000	43	9,885
MAIN	-	-	-	-	4	600	-	-	-	-	-	-	4	600
SPP	-	-	-	-	2	91	2	12	-	-	-	-	4	103
ERCOT	1	1,150	8	4,335	8	590	-	-	-	-	-	-	17	6,075
MAPP	-	-	-	-	6	180	-	-	-	-	-	-	6	180
WSCC	2	2,490	4	1,025	2	160	-	-	4	390	-	-	12	4,065
SCHEDULED ADDITIONS BY OWNERSHIP														
INVESTOR-OWNED	4	4,164	21	8,422	65	5,575	-	-	2	25	4	1,000	96	19,186
FEDERAL	4	4,780	-	-	-	-	-	-	2	230	-	-	6	5,010
MUNICIPAL	-	-	1	498	5	204	4	32	-	-	-	-	10	734
COOPERATIVE	-	-	2	1,000	3	280	-	-	-	-	-	-	5	1,280
STATE AND LOCAL	2	2,490	1	500	-	-	-	-	2	160	-	-	5	3,150

Table 17 - SCHEDULED ADDITIONS TO ELECTRIC GENERATING CAPABILITY
Based on Scheduled Dates of Commercial Operation as of January 1, 1990

SYMBOLS:

Investor-Owned.....I
Federal.....F
Municipal.....M
Cooperative.....C
State & Local.....SL

Thermal

- Conventional steam turbine-generator.....T
- Nuclear steam turbine-generator....N
- Combustion turbine-generator.....G
- Diesel engine-generator.....D

Hydraulic

- Hydraulic turbine-generator.....H

Pumped-Storage

- Pumped-storage turbine-generator.....S
- Reversible pumped-storage turbine-generator.....R

Combined-Cycle

- Combustion turbine-generator for combined-cycle operation.....GC
- Conventional steam turbine-generator for combined-cycle operation.....TC

+ Denotes multiple ownership of the unit. In such cases, the name of the participating power system in whose service area the installation will be located is shown. In case the location does not fall within the service area of any of the participants, the name of the power system shown is the first in alphabetical order among the major participants.

o Denotes units added to the expansion program since July 1, 1989.

NOTE: Megawatts shown for individual generating units represent, in most cases, the net operating capability expected by the utility systems; in other cases they represent the manufacturer's nameplate rating of the unit.

Table 17 -- SCHEDULED ADDITIONS as of JANUARY 1, 1990

REGION		SYSTEM	UNIT	OWNER-SHIP	TYPE	STEAM FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
NPCC		BOSTON EDISON CO	EDGAR GT NO 3	I	GC		100	1993
NPCC		BOSTON EDISON CO	EDGAR ST NO 3	I	TC		40	1993
NPCC		BOSTON EDISON CO	EDGAR ST NO 4	I	TC		40	1993
NPCC		BOSTON EDISON CO	EDGAR GT NO 4	I	GC		100	1993
NPCC	+	BOSTON EDISON CO	OCEAN STATE PWR NO 1	I	TC	Gas	250	1991
NPCC	+	BOSTON EDISON CO	OCEAN STATE PWR NO 1	I	GC		80	1991
NPCC	+	BOSTON EDISON CO	OCEAN STATE PWR NO 2	I	GC		80	1991
NPCC		CENTRAL MAINE POWER CO	MONTY NO 1	I	H		13	1990
NPCC		CENTRAL MAINE POWER CO	MONTY NO 2	I	H		13	1990
NPCC		LONG ISLAND LIGHTING CO	SHOREHAM NO 1	I	N		809	1990
NPCC		NEW ENGLAND POWER CO	MANCHESTER ST NO 09	I	G		97	1994
NPCC		NEW ENGLAND POWER CO	MANCHESTER ST NO 10	I	G		97	1995
NPCC		NEW ENGLAND POWER CO	MANCHESTER ST NO 11	I	G		97	1995
NPCC		PEABODY MASS	WATERS RIVER NO 1	M	G		29	1990
NPCC	+	PUB SERV NEW HAMPSHIRE	SEABROOK NO 1	I	N		1,150	1990
15								
MAAC		ATLANTIC ELECTRIC	CUMBERLAND CT NO 1	I	G		76	1990
MAAC		BALTIMORE GAS & ELEC CO	BRANDON SHORES NO 2	I	T	Oil/Coal	640	1991
MAAC		DELMARVA POWER & LT CO	HAY ROAD NO 3	I	G		105	1991
MAAC		DOVER DELAWARE	PARKLAND	M	G		35	1991
MAAC		PHILADELPHIA ELEC CO	LIMERICK NO 2	I	N		1,055	1990
MAAC		POTOMAC ELEC POWER CO	STATION H NO 1	I	G		127	1992
MAAC		POTOMAC ELEC POWER CO	STATION H NO 2	I	G		127	1993
MAAC		POTOMAC ELEC POWER CO	STATION H NO 3	I	G		127	1996
MAAC		POTOMAC ELEC POWER CO	STATION H NO 4	I	G		127	1998
MAAC		PUBLIC SERVICE ELEC & GAS	ESSEX NO 9	I	G		22	1990
MAAC		SO MARYLAND ELEC COOP	CHALK POINT	C	G		80	1991
11								

Table 17 -- SCHEDULED ADDITIONS as of JANUARY 1, 1990 (Cont'd)

REGION		SYSTEM	UNIT	OWNER-SHIP	TYPE	STEAM FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
ECAR		CINCINNATI GAS & ELEC CO	WOODSDALE NO 1	I	G		77	1993
ECAR		CINCINNATI GAS & ELEC CO	WOODSDALE NO 2	I	G		77	1992
ECAR		CINCINNATI GAS & ELEC CO	WOODSDALE NO 3	I	G		77	1992
ECAR		CINCINNATI GAS & ELEC CO	WOODSDALE NO 4	I	G		77	1992
ECAR		CINCINNATI GAS & ELEC CO	WOODSDALE NO 5	I	G		78	1992
ECAR		CINCINNATI GAS & ELEC CO	WOODSDALE NO 6	I	G		77	1992
ECAR	+	CINCINNATI GAS & ELEC CO	ZIMMER	I	T	Coal	1,300	1991
ECAR		EAST KENTUCKY PWR COOP	SMITH NO 1	C	T	Coal	600	2001
ECAR		LOUISVILLE GAS & ELEC CO	TRIMBLE COUNTY NO 1	I	T	Coal	495	1991
ECAR		SOUTHERN INDIANA G & E CO	BROWN NO 4	I	G		80	1991
10								

SERC		ALABAMA POWER CO	MILLER NO 4	I	T	Coal	667	1991
SERC		DUKE POWER CO	BAD CREEK NO 1	I	R		250	1992
SERC		DUKE POWER CO	BAD CREEK NO 2	I	R		250	1992
SERC		DUKE POWER CO	BAD CREEK NO 3	I	R		250	1993
SERC		DUKE POWER CO	BAD CREEK NO 4	I	R		250	1993
SERC		DUKE POWER CO	LINCOLN COUNTY NO 01	I	G		72	1994
SERC		DUKE POWER CO	LINCOLN COUNTY NO 02		t1988XG		72	1994
SERC		DUKE POWER CO	LINCOLN COUNTY NO 03	I	G		72	1994
SERC		DUKE POWER CO	LINCOLN COUNTY NO 04	I	G		72	1995
SERC		DUKE POWER CO	LINCOLN COUNTY NO 05	I	G		72	1995
SERC		DUKE POWER CO	LINCOLN COUNTY NO 06	I	G		72	1995
SERC		DUKE POWER CO	LINCOLN COUNTY NO 07	I	G		72	1995
SERC		DUKE POWER CO	LINCOLN COUNTY NO 08	I	G		72	1995
SERC		DUKE POWER CO	LINCOLN COUNTY NO 09	I	G		72	1995
SERC		DUKE POWER CO	LINCOLN COUNTY NO 10	I	G		72	1995
SERC		DUKE POWER CO	LINCOLN COUNTY NO 11	I	G		72	1996

Table 17 -- SCHEDULED ADDITIONS as of JANUARY 1, 1990 (Cont'd)

REGION	SYSTEM	UNIT	OWNER-SHIP	TYPE	STEAM FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
SERC	DUKE POWER CO	LINCOLN COUNTY NO 12	I	G		72	1996
SERC	DUKE POWER CO	LINCOLN COUNTY NO 13	I	G		72	1996
SERC	DUKE POWER CO	LINCOLN COUNTY NO 14	I	G		72	1996
SERC	DUKE POWER CO	LINCOLN COUNTY NO 15	I	G		72	1996
SERC	DUKE POWER CO	LINCOLN COUNTY NO 16	I	G		72	1996
SERC	FLORIDA POWER & LT CO	FORT LAUDERDALE #4A	I	GC		143	1993
SERC	FLORIDA POWER & LT CO	FORT LAUDERDALE #4B	I	GC		143	1993
SERC	FLORIDA POWER & LT CO	FORT LAUDERDALE #5A	I	GC		143	1993
SERC	FLORIDA POWER & LT CO	FORT LAUDERDALE #5B	I	GC		143	1993
SERC	FLORIDA POWER & LT CO	PT EVERGLADES NO 5	I	T		11	1990
SERC	KEY WEST FLORIDA	STOCK ISLAND NO 1	M	D		10	1991
SERC	KEY WEST FLORIDA	STOCK ISLAND NO 2	M	D		10	1991
SERC	OLD DOMINION ELEC COOP	CLOVER NO 1	C	T	Coal	400	1993
SERC	SO CAROLINA ELEC & GAS	HAGOOD GT	I	G		96	1991
SERC	SO CAR PUB SERV AUTHY	CROSS NO 1	SL	T	Coal	500	1999
SERC	TENN VALLEY AUTHY	BELLEFONTE NO 1	F	N		1,213	1997
SERC	TENN VALLEY AUTHY	BELLEFONTE NO 2	F	N		1,213	1999
SERC	TENN VALLEY AUTHY	WATTS BAR NO 1	F	N		1,177	1991
SERC	TENN VALLEY AUTHY	WATTS BAR NO 2	F	N		1,177	1994
SERC	VIRGINIA EL. & PR CO	CHESTERFIELD VA	I	G		127	1990
SERC	VIRGINIA ELECTRIC	CHESTERFIELD NO 7	I	T		58	1990
SERC	VIRGINIA ELECTRIC	CHESTERFIELD NO 8	I	T		58	1992
SERC	VIRGINIA ELECTRIC	CHESTERFIELD NO 8	I	G		127	1992
SERC	VIRGINIA ELECTRIC	DARBYTOWN NO 1	I	G		79	1990
SERC	VIRGINIA ELECTRIC	DARBYTOWN NO 2	I	G		79	1990
SERC	VIRGINIA ELECTRIC	DARBYTOWN NO 3	I	G		79	1990
SERC	VIRGINIA ELECTRIC	DARBYTOWN NO 4	I	G		79	1990
43							

Table 17 -- SCIEDULED ADD T ONS as of JANUARY 1, 1990 (Cont'd)

REGION		SYSTEM	UNIT	OWNER-SHIP	TYPE	STEAM FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
MAIN		WISCONSIN ELEC POWER CO	WATERTOWN GT NO 1	I	G		150	1993
MAIN		WISCONSIN ELEC POWER CO	WATERTOWN GT NO 2	I	G		150	1994
MAIN		WISCONSIN ELEC POWER CO	WATERTOWN GT NO 3	I	G		150	1995
MAIN		WISCONSIN ELEC POWER CO	WATERTOWN GT NO 4	I	G		150	1996
4								
SPP		CUSHING OKLAHOMA	MUNI POWER PLANT	M	D		6	1990
SPP		LUBBOCK TEXAS	TECH NO 1	M	G		20	1990
SPP		MARSHALL MISSOURI	NO 7	M	D		6	1990
SPP		SPRINGFIELD MO	SPRINGFIELD GT NO 1	M	G		71	1990
4								
		BRAZOS ELECTRIC COOP	MILLER NO 4	C	G		100	1994
ERCOT		BRAZOS ELECTRIC COOP	MILLER NO 5	C	G		100	1994
ERCOT		HOUSTON LIGHTING & PR CO	MALAKOFF NO 1	I	T	Coal	645	1996
ERCOT		HOUSTON LIGHTING & PR CO	MALAKOFF NO 2	I	T	Coal	645	1998
ERCOT		SAN ANTONIO TEXAS	J K SPRUCE NO 1	M	T	Coal	498	1992
ERCOT		TEXAS-NEW MEXICO PR CO	TNP ONE NO 1	I	T	Coal	149	1990
ERCOT		TEXAS-NEW MEXICO PR CO	TNP ONE NO 2	I	T	Coal/Gas	149	1991
ERCOT	+	TEXAS UTILITY CO SYSTEM	COMANCHE PEAK NO 2	I	N		1,150	1992
ERCOT	+	TEXAS UTILITY CO SYSTEM	FOREST GROVE NO 1	I	T	Coal	750	1997
ERCOT		TEXAS UTILITY CO SYSTEM	DE CORDOVA CT NO 1	I	G		65	1990
ERCOT		TEXAS UTILITY CO SYSTEM	DE CORDOVA CT NO 2	I	G		65	1990
ERCOT		TEXAS UTILITY CO SYSTEM	DE CORDOVA CT NO 3	I	G		65	1990
ERCOT		TEXAS UTILITY CO SYSTEM	DE CORDOVA CT NO 4	I	G		65	1990
ERCOT		TEXAS UTILITY CO SYSTEM	PERMIAN BASIN CT 4	I	G		65	1990
ERCOT		TEXAS UTILITY CO SYSTEM	PERMIAN BASIN CT 5	I	G		65	1990
ERCOT	+	TEXAS UTILITY CO SYSTEM	TWIN OAK NO 1	I	T	Coal	750	1994
ERCOT	+	TEXAS UTILITY CO SYSTEM	TWIN OAK NO 2	I	T	Coal	750	1995
17								

Table 17 -- SCHEDULED ADDITIONS as of JANUARY 1, 1990 (Cont'd)

REGION		SYSTEM	UNIT	OWNER-SHIP	TYPE	STEAM FOSSIL FUELS	MW of NET EXPECTED CAPABILITY	SKED YEAR OPTN
MAPP		INTERSTATE POWER CO	MASON CITY NO 1	I	G		30	1991
MAPP		INTERSTATE POWER CO	MASON CITY NO 2	I	G		30	1991
MAPP		IOWA POWER & LIGHT CO	PLEASANT HILL A	I	G		38	1990
MAPP		IOWA POWER & LIGHT CO	PLEASANT HILL B	I	G		38	1990
MAPP		IOWA SOUTHERN UTILS CO	GRINNELL GT NO 1	I	G		22	1990
MAPP		IOWA SOUTHERN UTILS CO	GRINNELL GT NO 2	I	G		22	1990
6								
WSCC		ANAHEIM CALIFORNIA	GAS TURBINE SS	M	G		50	1991
WSCC		CALIF DEPT WATER RES	DEVIL CANYON NO 3	SL	H		80	1992
WSCC		CALIF DEPT WATER RES	DEVIL CANYON NO 4	SL	H		80	1992
WSCC		NEVADA POWER CO	CLARK NO 9	I	TC		90	1993
WSCC		NEVADA POWER CO	CLARK NO 10	I	TC		90	1994
WSCC		PUB SERV CO OF COLO	PAWNEE NO 2	I	T	Coal	485	1998
WSCC		SAN DIEGO G & E CO	SOUTH BAY NO 3	I	G		110	1993
WSCC		TUCSON ELEC POWER CO	SPRINGERVILLE NO 2	I	T	Coal	360	1990
WSCC		U S BUREAU OF RECLAM	HOOVER A3	F	H		115	1992
WSCC		U S BUREAU OF RECLAM	HOOVER A4	F	H		115	1992
WSCC	+	WASHINGTON PPSS	WNP NO 3	SL	N		1,240	1999
WSCC	+	WASHINGTON PPSS	WNP NO 1	SL	N		1,250	1999
12								
		TOTAL				122 Units:	29,360	MW

Table 18 – CAPACITIES OF VARIOUS TYPES OF HEAVY ELECTRIC POWER EQUIPMENT ORDERED BY U.S. ELECTRIC UTILITY SYSTEMS FROM DOMESTIC AND FOREIGN MANUFACTURERS

	1985	1986	1987	1988	1989
Electric Generating Units (4,000 kW and Larger)					
Steam Turbine–Generators, kW					
Conventional	1,379,454	--	220,400	860,600	579,000 (a)
Nuclear	--	--	--	--	--
Geothermal, kW	168,000 (a)	--	--	--	--
Solar, kW	90,000	--	--	--	--
Combustion Turbine–Generators, kW	24,800	751,800	824,500 (a)	1,571,300 (a)	4,816,000 (a)
Generators for Hydraulic Turbines, kW	69,200	--	20,400 (a)	126,000 (a)	396,800 (a)
	1,731,454 (a)	751,800	1,065,300 (a)	2,557,900 (a)	5,791,800 (a)
Steam Generators, 1,000 Lb Steam Per Hour	--	9,775	--	250	4,100
Nuclear Power Reactors (50,000 kWe and Larger)	--	--	--	--	--
Hydraulic Turbines, Hp	--	77,200 (a)	--	145,600	59,300 (a)
Power Transformers, Mva (b)	65,037	79,662	78,233	82,502	88,180

(a) Includes equipment on order with foreign manufacturers.
(b) Includes U.S. industrials.

Table 19 MANUFACTURE OF ELECTRIC GENERATING EQUIPMENT STEAM, HYDRAULIC and COMBUSTION TURBINE UNITS* -- 4,000 kW and Larger

Customer	Shipped	Scheduled as of January 1, 1990		Total Scheduled for Shipment as of 1-1-90	New Orders Booked
	1989	1990	1991 and Later		1989
U.S. Electric Utility Systems					
Units	17	24	40	64	44
kW	792,100	3,408,326	7,974,977	11,383,303	3,970,100
U.S. Industrials					
Units	40	69	28	97	96
kW	1,388,500	3,098,703	1,946,825	5,045,528	5,010,403
Exports from U.S.					
Units	17	10	24	34	28
kW	1,937,780	3,515,300	8,044,000	11,559,300	4,588,800
Total					
Units	74	103	92	195	168
kW	4,118,380	10,022,329	17,965,802	27,988,131	13,569,303

* Includes Steam Turbine-Generators for Nuclear Power Plants.
** Manufacturers' Ratings.

Table 20 MANUFACTURE OF STEAM TURBINE-GENERATORS

4,000 kW and Larger

Customer	Shipped	Scheduled as of January 1, 1990		Total Scheduled for Shipment as of 1-1-90	New Orders Booked
	1989	1990	1991 and Later		1989
U.S. Electric Utility Systems					
Units	4	5	12	17	2
kW	241,700	2,051,526	5,121,377	7,172,903	499,000
U.S. Industrials					
Units	19	33	16	49	49
kW	521,800	1,289,703	862,825	2,152,528	2,130,203
Exports from U.S.					
Units	3	5	16	21	10
kW	637,380	3,100,000	6,348,000	9,448,000	1,948,000
Total					
Units	26	43	44	87	61
kW	1,400,880	6,441,229	12,332,202	18,773,431	4,577,203

Table 20-A MANUFACTURE OF CONVENTIONAL STEAM TURBINE-GENERATORS

4,000 kW and Larger (Included in Table 20)

Customer	Shipped	Scheduled as of January 1, 1990		Total Scheduled for Shipment as of 1-1-90	New Orders Booked
	1989	1990	1991 and Later		1989
U.S. Electric Utility Systems					
Units	4	5	12	17	2
kW	241,700	2,051,526	5,121,377	7,172,903	499,000
U.S. Industrials					
Units	19	33	16	49	49
kW	521,800	1,289,703	862,825	2,152,528	2,130,203
Exports from U.S.					
Units	3	3	13	16	10
kW	637,380	1,700,000	3,648,000	5,348,000	1,948,000
Total					
Units	26	41	41	82	61
kW	1,400,880	5,041,229	9,632,202	14,673,431	4,577,203
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	–	–	2	2	2
kW	–	–	80,000	80,000	80,000
U.S. Industrial Orders to Foreign Manufacturers					
Units	26	15	13	28	29
kW	2,330,156	851,400	861,700	1,713,100	1,721,100

Table 20-B MANUFACTURE OF NUCLEAR STEAM TURBINE-GENERATORS

50,000 kWe and Larger (Included in Table 20)

[revise figures]	Shipped	Scheduled as of January 1, 1990		Total Scheduled for Shipment as of 1-1-90	New Orders Booked 1989
Customer	1989	1990	1991 and Later		
U.S. Electric Utility Systems					
Units	-	-	-	-	-
kW	-	-	-	-	-
U.S. Industrials					
Units	-	-	-	-	-
kW	-	-	-	-	-
Exports from U.S.					
Units	-	2	3	5	-
kW	-	1,400,000	2,700,000	4,100,000	-
Total					
Units	-	2	3	5	-
kW	-	1,400,000	2,700,000	4,100,000	-
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	-	-	-	-	-
kW	-	-	-	-	-

Table 21 MANUFACTURE OF GENERATORS FOR HYDRAULIC TURBINES* – 4,000 kW and Larger

Customer	Shipped	Scheduled as of January 1, 1990		Total Scheduled for Shipment as of 1–1–90	New Orders Booked
	1989	1990	1991 and Later		1989
U.S. Electric Utility Systems					
Units	–	–	–	–	–
kW	–	–	–	–	–
U.S. Industrials					
Units	–	–	–	–	–
kW	–	–	–	–	–
Exports from U.S.					
Units	–	–	–	–	–
kW	–	–	–	–	–
Total					
Units	–	–	–	–	–
kW	–	–	–	–	–
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	6	2	4	6	4
kW	721,000	563,400	396,800	960,200	396,800
U.S. Industrial Orders to Foreign Manufacturers					
Units	–	3	–	3	3
kW	–	23,000	–	23,000	23,000

Table 22 MANUFACTURE OF CONVENTIONAL STEAM GENERATORS -- 450 Psi and Higher

Customer	Shipped	Scheduled as of January 1, 1990		Total Scheduled for Shipment as of 1-1-90	New Orders Booked
	1989	1990	1991 and Later		1989
U.S. Electric Utility Systems					
Units	5	3	6	9	2
M Lb/Hr	29,700	11,156	25,231	36,387	4,100
U.S. Industrials					
Units	1	8	-	27	26
M Lb/Hr	230	2,438	-	16,970	17,066
Exports from U.S.					
Units	2	1	-	1	1
M Lb/Hr	8,068	4,459	-	4,459	4,459
Total					
Units	8	12	6	37	29
M Lb/Hr	37,998	18,053	32,037	57,816	25,625

Table 23 MANUFACTURE OF HYDRAULIC TURBINES

5,000 Horsepower and Larger

Customer	Shipped	Scheduled as of January 1, 1990		Total Scheduled for Shipment as of 1-1-90	New Orders Booked
	1989	1990	1991 and Later		1989
U.S. Electric Utility Systems					
Units	–	–	10	10	–
Hp	–	–	1,529,360	1,529,360	–
U.S. Industrials					
Units	2	2	–	2	–
Hp	14,000	80,775	–	80,775	–
Exports from U.S.					
Units	–	–	1	1	–
Hp	–	–	135,000	135,000	–
Total					
Units	2	2	12	13	–
Hp	14,000	80,775	1,664,360	1,745,135	–
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	2	1	1	2	2
Hp	134,320	47,100	12,200	59,300	59,300
U.S. Industrial Orders to Foreign Manufacturers					
Units	–	–	–	–	–
Hp	–	–	–	–	–

Table 24 MANUFACTURE OF COMBUSTION TURBINE-GENERATORS

4,000 kW and Larger

Customer	Shipped	Scheduled as of January 1, 1990		Total Scheduled for Shipment as of 1-1-90	New Orders Booked
	1989	1990	1991 and Later		1989
U.S. Electric Utility Systems					
Units	13	19	28	47	42
kW	550,400	1,356,800	2,853,600	4,210,400	3,471,100
U.S. Industrials					
Units	21	36	12	48	47
kW	866,700	1,809,000	1,084,000	2,893,000	2,880,200
Exports from U.S.					
Units	14	5	8	13	18
kW	1,300,400	415,300	1,696,000	2,111,300	2,640,800
Total					
Units	48	60	48	108	107
kW	2,717,500	3,581,100	5,633,600	9,214,700	8,992,100
U.S.E.U.S. Orders to Foreign Manufacturers (Imports)					
Units	2	3	14	17	15
kW	200,000	303,000	1,242,000	1,545,000	1,345,000
U.S. Industrial Orders to Foreign Manufacturers					
Units	10	2	5	7	6
kW	1,545,500	128,000	505,800	633,800	540,000

Table 25 MANUFACTURE OF NUCLEAR REACTORS

50,000 kWe and Larger

Customer	Completed	Scheduled as of January 1, 1990		Total Scheduled as of 1-1-90	New Orders Booked
	1989	1990	1991 and Later		1989
U.S. Electric Utility Systems					
Units	4	2	8	10	-
kWe	4,568,000	2,020,000	9,702,000	11,722,000	-
Exports from U.S.					
Units	-	1	7	8	-
kWe	-	654,000	7,086,000	7,740,000	-
Total					
Units	4	3	15	18	-
kWe	4,568,000	2,674,000	16,788,000	19,462,000	-

Table 26 -- MANUFACTURE OF POWER TRANSFORMERS, 501 kVA and Larger

Customer		Shipped 1989	Scheduled as of January 1, 1990 1990	1991	1992	1993	1994	1995	1996 and Later	Total Scheduled for Shipment as of 1-1-90	Orders Booked 1989
					501 to 10,000 kVA						
U.S. Electric Utility Systems and U.S. Industrials	(Units	4,961	2,477	3	2	11	-	-	-	2,493	5,536
	(MVA	12,982	7,077	29	20	61	-	-	-	7,187	15,720
Exports from U.S.	(Units	160	192	-	-	-	-	-	-	192	164
	(MVA	446	493	-	-	-	-	-	-	493	497
TOTAL	(Units	5,121	2,669	3	2	11	-	-	-	2,685	5,700
	(MVA	13,428	7,570	29	20	61	-	-	-	7,680	16,217
					10,001 to 30,000 kVA						
U.S. Electric Power Systems and U.S. Industrials	(Units	663	531	45	2	4	-	-	-	582	703
	(MVA	17,034	11,785	1,137	100	148	-	-	-	13,170	17,667
Exports from U.S.	(Units	9	2	-	-	-	-	-	-	2	10
	(MVA	253	40	-	-	-	-	-	-	40	232
TOTAL	(Units	672	533	45	2	4	-	-	-	584	713
	(MVA	17,287	11,825	1,137	100	148	-	-	-	13,210	17,899
					30,001 to 100,000 kVA						
U.S. Electric Utility Systems and U.S. Industrials	(Units	324	246	25	-	-	-	-	-	271	331
	(MVA	21,320	14,674	1,193	-	-	-	-	-	15,867	20,484
Exports from U.S.	(Units	-	-	-	-	-	-	-	-	-	-
	(MVA	-	-	-	-	-	-	-	-	-	-
TOTAL	(Units	324	246	25	-	-	-	-	-	271	331
	(MVA	21,320	14,674	1,193	-	-	-	-	-	15,867	20,484
					100,000 kVA and Larger						
U.S. Electric Power Systems and U.S. Industrials	(Units	90	87	17	2	-	-	-	-	106	103
	(MVA	29,279	26,895	5,881	1,680	-	-	-	-	34,455	34,309
Exports from U.S.	(Units	-	-	-	-	-	-	-	-	-	1
	(MVA	-	-	-	-	-	-	-	-	-	400
TOTAL	(Units	90	87	17	2	-	-	-	-	106	104
	(MVA	29,279	26,895	5,881	1,680	-	-	-	-	34,455	34,709
					Total (501 kVA and Larger)						
U.S. Electric Utility Systems and U.S. Industrials	(Units	6,038	3,341	90	6	15	-	-	-	3,452	6,673
	(MVA	80,615	60,431	8,240	1,800	209	-	-	-	70,679	88,180
Exports from U.S.	(Units	169	194	-	-	-	-	-	-	194	175
	(MVA	699	533	-	-	-	-	-	-	533	1,129
TOTAL	(Units	6,207	3,535	90	6	15	-	-	-	3,646	6,848
	(MVA	81,314	60,964	8,240	1,800	209	-	-	-	71,212	89,309

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